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Part II

Environmental Protection Agency

Water Programs; Consolidated Permit Regulations and Technical Criteria and Standards; State Underground Injection Control Programs

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 122 and 146

[FRL 1482-1]

Water Programs; Consolidated Permit Regulations and Technical Criteria and Standards; State Underground Injection Control Programs

AGENCY: Environmental Protection Agency.

ACTION: Final Rule for Part 146 and Amendments to Part 122.

SUMMARY: The Safe Drinking Water Act requires the Environmental Protection Agency (EPA) to develop minimum requirements for State programs to protect underground drinking water sources from endangerment by the subsurface emplacement of fluids through well injection. Such regulations have been established in the recently published Consolidated Permit regulations. The regulations promulgated here today establish the technical criteria and standards for use by States and EPA in the development and implementation of such State UIC programs. Neither these regulations nor the Consolidated Permit regulations establish requirements for owners or operators of injection wells at this time, with one exception. They establish requirements for State or EPA officials to be used in developing State UIC programs which, when they become effective, will in turn establish enforceable requirements for owners or operators of injection wells.

The one exception concerns owners or operators of wells which inject hazardous waste within the meaning of the Resource Conservation and Recovery Act (RCRA). Owners or operators of such wells must achieve interim status under the Hazardous Waste Management program, even though such injection practices will ultimately be controlled under the Safe Drinking Water Act once a State UIC program becomes effective.

Subpart A of these regulations spells out certain general provisions with respect to underground sources of drinking water, the classification of injection wells, the use of the area of review concept, corrective action requirements, mechanical integrity, criteria for establishing permitting priorities, and requirements for the abandonment of Class I, II and III wells. Subparts B through F of these regulations establish technical requirements and criteria that the Director is to apply in regulating the construction, operation, monitoring and reporting of wells in Classes I through V. In the case of wells in Classes I through III, Subparts B through D also detail the information that the Director is to consider prior to the issuance of a permit.

During the final drafting of these Part 146 regulations, it became apparent that some changes to the Consolidated Permit Regulations were necessary. Six amendments involving four sections are included in this publication and are discussed in this preamble.

DATES: The regulations in this promulgation shall become effective on July 18, 1980 or thirty (30) days after their publication in the **Federal Register** (July 24, 1980), whichever is later. That date shall also be the implementation date for those portions of 40 CFR Parts 122, 123 and 124 which relate to Underground Injection Control (UIC) permits and programs (see 45 FR 33290).

The Safe Drinking Water Act allows States 270 days from the effective date of these regulations to develop programs which meet the regulatory requirements of 40 CFR Parts 122, 123, 124 and 146, and to submit such programs to EPA for approval. This period may be extended by another 270 days for good cause.

In order to assist EPA to correct typographical errors, incorrect cross-references, and similar technical errors, comments of a technical and non-substantive nature on the final regulations may be submitted until July 24, 1980. The effective date will not be delayed by consideration of such comments.

ADDRESSES: Comments of a technical and non-substantive nature should be addressed to, Thomas Belk, Chief, Ground Water Protection Branch, EPA, Office of Drinking Water (WH-550), Washington, D.C. 20460 (202) 426-3985.

FOR FURTHER INFORMATION CONTACT: Thomas Belk, Chief, Ground Water Protection Branch, Environmental Protection Agency, (202) 426-3985.

SUPPLEMENTARY INFORMATION:

Legal Authority

General

These regulations are being proposed under the authority of the Safe Drinking Water Act (the "Act" or "SDWA"), Pub. L. 93-523, December 16, 1974, as amended by Pub. L. 95-190, November 16, 1977. The Act is designed to protect the quality of drinking water in the United States.

Part A of the Act (section 1401) contains definitions. Part B (sections 1411-1416) addresses the quality of water provided by public water supplies. EPA regulations implementing Part B of the Act are codified at 40 CFR Parts 141 and 142.

The regulations below relate to Part C of the Act (sections 1421-1424), entitled "Protection of Underground Sources of Drinking Water."

Basis for Concern

The legislative history of the Act reflects the basic Congressional concerns in enacting part C of the Act:

> "* * * underground injection of contaminants is clearly an increasing problem. Municipalities are increasingly engaging in underground injection of sewage, sludge, and other wastes. Industries are injecting chemicals, by-products, and wastes. Energy production companies are using injection techniques to increase production and dispose of unwanted brines brought to the surface during production. Even government agencies, including the military, are getting rid of difficult to manage waste problems by underground disposal methods. Part C is intended to deal with all the foregoing situations insofar as they may endanger underground drinking water sources." (HR Report No. 93-1185, July 10, 1974, p. 29).

The potentially dangerous practices which Congress sought to control in 1974 continue at an ever increasing rate. EPA estimates that there are in excess of 400,000 municipal, industrial, commercial, agricultural, and domestic wells currently injecting fluids below the surface, and that there are at least 5,000 new wells of these types each year. The purpose of Part C of the Act, and of the Underground Injection Control (UIC) program, is to establish a Federal-State system of controls which will insure that such underground injection practices do not endanger drinking water sources.

Relevant Statutory Provisions

A detailed discussion of the relevant statutory provisions and legislative history appears in earlier proposals of these regulations (41 FR 36730 et seq., August 31, 1976 and 44 FR 23738 et seq., April 20, 1979). Those details need not be repeated here, but it is useful to summarize the basic scheme of Part C of the Act.

1. *Section 1421: Minimum Requirements for State Programs*— Section 1421 requires EPA to propose and promulgate regulations specifying "minimum requirements" for State programs to prevent underground injections which endanger drinking water sources. Such minimum requirements must provide for at least the following:

- A program prohibiting any underground injection which is not authorized by a State permit. EPA may, at its discretion, however, allow some or

all underground injections to be authorized by rules without case-by-case permits (section 1421(b)(1)(A)).

• Protection of underground drinking water sources.

• Inspection, monitoring, record keeping, and reporting requirements (section 1421(b)(1)(C)).

• Coverage of underground injections by Federal Agencies and underground injections by any person on property owned or leased by the United States (section 1421(b)(1)(D)).

2. *Section 1422(a): List of States*—Section 1422(a) requires EPA to list in the Federal Register each State for which an underground injection control program "may be necessary" to ensure that underground injections will not endanger drinking water sources. With the recent listing of the remaining 16 jurisdictions (45 FR 17632), EPA has now listed all 50 States, the District of Columbia, and the Territories and Possessions of the United States (hereafter "States"). Such listings are hereby confirmed.

One major consideration in listing all of the States and other jurisdictions as needing UIC programs is that in the next few years the Agency will embark on a broad effort to protect ground water throughout the United States. EPA wishes to avoid instances where the surface disposal of hazardous wastes is controlled or prohibited under the Hazardous Waste Management (HWM) program mandated by the Resource Conservation and Recovery Act (RCRA), Pub. L. 94–580, October 21, 1976, while the underground injection of the same hazardous waste is not regulated by effective State programs. EPA is concerned that such a situation would create undesirable incentives to avoid regulations under the Hazardous Waste Management program by disposing of those regulated wastes below the surface. By listing all the States the Agency intends to bring the disposal of hazardous waste through well injection under regulatory control in a comparable time period with the control of surface disposal of hazardous waste under the Resource Conservation and Recovery Act.

3. *Section 1422(b)(d): Development of Underground Injection Control Programs*—Once EPA has promulgated the "minimum requirements" regulations, each State will have the opportunity to develop an enforceable underground injection control program. The UIC program must be adopted after reasonable notice and public hearings, and must comply with the minimum requirements.

Each State will have 270 days from the effective date of these regulations to develop its UIC program and submit it to EPA for review. EPA may, for a good cause, extend this deadline for any State by up to an additional 270 days. The Agency does not intend to follow a liberal policy in granting extensions. "Good cause" will be limited to the need to obtain legal authority from the legislature and similar reasons.

If EPA determines that a State UIC program meets the minimum requirements of Parts 123 and 146, EPA will approve the program. The State will then be deemed to have "primary enforcement responsibility" under Part C of the Act and there will be no Federal UIC enforcement actions in that State so long as the State continues to meet its responsibilities.

If a State fails to adopt and submit a UIC program in a timely fashion, or if EPA finds that a State's UIC program fails in part or in whole to meet the minimum requirements of Parts 123 and 146, EPA is required to propose and promulgate UIC regulations to be effective in that State. In such an event, a State will not be deemed to have "primary enforcement responsibility," ("primacy") and direct Federal enforcement of the UIC program will result (section 1422 (b), (c), 1423). In addition, a State which fails to achieve full primacy within 2 years of the award of its first UIC grant loses eligibility for further Federal grants.

4. *The 1977 Amendments*—Although they do not vary the operating scheme of Part C of the Act, the 1977 amendments to the Act, Pub. L. 95–190, should be noted. In addition to allowing the 270 day extension for State submission of requests for approval of State programs (see above), they emphasize that States have jurisdiction over injection by Federal Agencies or on Federal lands within the State. Federal Agencies fall under State regulations as would any other "person" (section 1447(a)). With respect to injection wells on Indian lands, however, jurisdiction remains with EPA (section 1447(a)).

New Section 1421(b)(3) instructs EPA to allow consideration of varying geologic, hydrologic, and historic conditions among States. The Section further cautions EPA against fashioning minimum requirements regulations which would "unnecessarily disrupt" existing State underground injection control programs now being enforced. These considerations however, may not be used to compromise the overall statutory requirement to prevent endangerment to underground sources of drinking water (section 1421(b)(3)(c)). EPA believes that these regulations amply serve these interests: the regulations offer States discretion to tailor local programs to meet specific needs and to consider geologic, hydrologic, and historic conditions in fashioning rules and permit requirements.

History of Rule Making

EPA originally proposed regulations to implement Part C of the Safe Drinking Water Act on August 31, 1976 (41 FR 36730–45). That proposal included the program regulations, the technical criteria and standards, and the related grant regulations. Four hundred twenty nine (429) written sets of comments were filed and many persons commented at public hearings in Dallas, Denver, and Washington, D.C.

After careful review of those public comments, EPA determined that there were many ways that the initial proposal could be made generally more flexible and less burdensome without sacrificing the resulting environmental protection to any significant degree. Further, in the fall of 1978, the Agency decided to consolidate the regulations for its major permit programs: the Hazardous Waste Management program under the Resource Conservation and Recovery Act (RCRA); the UIC program under the Safe Drinking Water Act (SDWA); and the National Pollutant Discharge Elimination System (NPDES) under the Clean Water Act (CWA).

As a consequence of these events, the Agency took the following series of actions in 1978 and 1979. The grant regulations related to the UIC program were promulgated in final form on October 12, 1978 (43 FR 47130, *et seq.*). The initial group of 22 States needing an UIC program were listed on September 25, 1978 (43 FR 43420). In addition the UIC program regulations were reproposed in four parts on April 20 and June 14, 1979:

• 40 CFR Part 122 reproposed the regulatory framework for the UIC program.

• 40 CFR Part 123 described the elements of an approvable State program and proposed the process for EPA approval of State participation in the UIC program.

• 40 CFR Part 124 described the procedures for permit application and issuance which EPA intends to follow when it has primacy. Certain provisions of 40 CFR Part 124 would also be applicable to State UIC programs.

• 40 CFR Part 146 (being promulgated here) proposed the technical criteria and standards to be used by EPA or the State in implementing the UIC program.

Numerous written comments were received and five public hearings were held in Dallas, Washington, D.C., Chicago, Seattle, and Denver on the

Consolidated Permit regulations and Part 146. The preamble to the Consolidated Permit regulations responds to both the written and oral comments addressed to Parts 122, 123, and 124. Two hundred sets of written comments were received addressed to Part 146. These together with the oral comments received will be responded to in this preamble.

As noted in the preamble to the reproposed Part 146 (44 FR 23742), an effort has been made in the process of promulgating these regulations to reduce duplication by retaining only technical criteria and standards in Part 146 and transferring all programmatic requirements to Parts 122, 123 and 124.

It is not necessary to repeat here the requirements established and explained in the Consolidated Permit regulations. The reader is referred to 45 FR 33290. It is, however, important to emphasize that, in contrast to the 1979 proposal, the final Part 122 regulation requires owners or operators of wells used to inject hazardous waste to achieve interim status under RCRA until the controlling State UIC program becomes effective. Therefore, the totality of requirements applicable to State UIC programs are to be found in six sets of regulations.

- The UIC program grant regulations (43 FR 47130).
- 40 CFR Part 122 (45 FR 33418).
- 40 CFR Part 123 (45 FR 33456).
- 40 CFR Part 124 (45 FR 33484).
- 40 CFR Part 146 (Published here today).
- 40 CFR Part 265 (45 FR 33260).

Response to Comments

The preamble to the 1979 reproposal of Part 146 requested comments from the public in more than 20 instances. Additional comments were requested in the preamble to the Consolidated Permit regulations as well. Even though the programmatic requirements for the Underground Injection Control program are properly dealt with in the preamble to the Consolidated Permit regulations, it is desirable to discuss them at least in part here since the technical criteria and standards are an integral portion of the Underground Injection Control program. In addition, it is appropriate to err on the side of completeness, even at the risk of repetition, for the sake of a comprehensible discussion of the issues involved.

I. *Regulatory Framework*

A. Coverage of the Regulations—1. *Wells not near underground sources of drinking water.* In the preamble to the 1979 reproposal of Part 146, EPA explained that, at one point in developing these regulations, EPA considered not applying these regulations to wells that do not inject into, through, or above drinking water sources (44 FR 23740–1). The preamble went on to explain the Agency's concern that such a provision could leave an injector uncertain about whether he is or is not covered by these regulations. Furthermore, although a particular well may not be injected into, through or above a drinking water source, it could still be a potential cause of endangerment by displacing formation fluids, through a hydraulic connection, into an underground source of drinking water.

In view of these concerns, the proposal suggested applying the regulations to all injection wells regardless of their location. The preamble went on to note that one result of this decision was that off-shore injection operations would be subjected to UIC regulations. In response, a number of commenters urged that off-shore operations be excluded from the coverage of the UIC program and that wells that do not inject into, through or above a drinking water source should be given recognition in some form. EPA agrees and the final Part 122 includes two sections intended to resolve this question.

First, § 122.31(d)(2)(i) excludes injection wells located on a drilling platform or other site beyond a State's territorial waters. The rationale behind this decision is that the Safe Drinking Water Act intended the underground injection control program to be a State program. Therefore, only injection wells that fall within the boundaries of a State are included and off-shore wells which fall beyond State boundaries are excluded.

Second, a new § 122.43(a) has been added. This section states that if a well does not inject into, through or above a drinking water source, the Director has discretion to ease the area of review, construction, mechanical integrity, monitoring, operating and reporting requirements applicable to such wells. In this regard EPA contemplated excluding such wells entirely from these regulations. However, it is only prudent that as long as an injection facility has some potential to contaminate underground sources of drinking water through lateral displacement, some minimal control should be exercised over it. At a minimum, the Director should have the opportunity to assess the potential for contamination. Thus, wells that do not inject into, through or above underground source of drinking water are still covered by the UIC program, so that they can be inventoried and their potential for endangerment reviewed. However, discretion is given to the Director to determine whether any additional requirements need be applied in particular instances.

2. *The Inclusion of Class II Wells.* The overwhelming majority of people commenting on the regulations on behalf of the oil and gas industry and the State regulatory agencies suggested that EPA should not bring Class II wells (those injection wells associated with the oil and gas industry) under the UIC regulations. Commenters advanced three reasons in support of this suggestion. First of all, they contended that EPA has failed to prove extensive damage to underground sources of drinking water from Class II injection practices. Second, the commenters maintained that existing State programs have done an effective job of preventing the contamination of underground sources of drinking water through Class II practices. Third, the commenters pointed out that Section 1422(c) of the SDWA instructs EPA not to include any requirements in its UIC regulations which interfere with or impede the disposal of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or any underground injection for the secondary or tertiary recovery of oil or natural gas, unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection.

A number of commenters also argued that natural gas storage facilities should be excluded from the regulations for reasons similar to the ones cited above, and because natural gas is neither a fluid nor a contaminant within the meaning of the SDWA.

EPA has carefully reviewed these comments and concludes that injection wells involved in natural gas storage operations do constitute underground injection within the meaning of the Act, and should be subject to these regulations. Section 1421(b)(1)(A) of the SDWA states that a State program, in order to be approved under Section 1422:

> "* * * shall prohibit, effective three years after the date of the enactment of this Title any underground injection in such State which is not authorized by a permit issued by the State to authorize underground injection by rule);"

The term "underground injection" is defined in Section 1421(d) of the Act as the subsurface emplacement of fluids by well injection. In scientific usage, the term "fluids" is defined to include not only liquids that flow but also gases. Thus, reading these two provisions of the Act together, there seems to be little

question that EPA does have the authority to bring both natural gas storage wells and other injection wells related to oil and gas production under the control of the Act. A more precise statement of the issue then would seem to be the appropriate level of regulation to which such practices should be subjected.

After a careful review of the comments on this point, the Agency has decided that further easing of the requirements for gas storage wells is appropriate for several reasons. First, EPA agrees with the comments that pointed out that unlike the injection of other substances, gas is highly unlikely to result in the chemical contamination of drinking water, even if it migrates from the injection zone. Second, the Agency is persuaded by the arguments that these facilities are used to store a valuable commodity and that, therefore, the operator has a strong incentive to be able to recover the stored gas with minimal losses to the environment.

However, after a further review of the pathways of possible contamination, the Agency has concluded that the major concern is any possible contamination of underground sources of drinking water from the displacement of formation fluids when gas is stored in aquifers.

The Agency's final decision is to classify gas storage operations in Class V. As such they will be authorized by rule in satisfaction of the requirement in Section 1421(b)(1)(A) of the Act, and be subject to further study. If States, based on their assessment, recommend further regulatory controls for gas storage wells, appropriate requirements may be established in the future.

With regard to the argument concerning existing effective State programs, the Act does not set any procedures or standards for EPA to follow in deciding which States to list. The Committee Report, on the other hand (H.R. Report 93–1185, page 32), states that it was anticipated by the Committee that EPA will list all 50 States but perhaps not the District of Columbia and various territories and possessions.

Furthermore, EPA has deliberately chosen to avoid any evaluation of the quality of existing State programs or the preparation of a "report card" as the basis for the Administrator's decision to list or not to list. There are several persuasive reasons for this course of action. First of all, a significant amount of EPA resources would be consumed in the process of doing careful evaluations of all of the 50 States UIC programs as they exist today. Such a nationwide evaluation process would require years to complete, involve hundreds of EPA personnel, and cost millions of dollars of contract support funds. Secondly, such an essentially adversary relationship could easily lead to embarrassment and resentment between States and EPA. It is not likely to be conducive to the long term objective of an effective State/Federal partnership in the implementation of UIC programs.

At one point in the development of the UIC program, it was the intention of the Agency to stagger the workload by phasing in the listing of States. It was to carry out the phasing that EPA developed the system of priorities to select the States which should be listed first. Factors to be considered in establishing such priorities included those approximating the potential threat (such as the number of wells in each State) and those approximating the importance of the ground water resources (such as the percent and absolute number of people relying on ground water). The basis for establishing priorities is given a fuller explanation in the Preamble to the initial listing of 22 States (43 FR 43420).

It should be emphasized that the Agency has always intended to list all States in keeping with the congressional guidance. The priority system discussed above was always intended as a basis for identifying the States to be listed first, not as a basis for deciding which States did or did not need a program.

In the process of consolidating the Agency's major permit program, however, it became apparent that the UIC program and the Hazardous Waste Management program are related at a number of points. The Agency, therefore, accelerated the listing of States in order to apply regulatory controls under UIC and HWM in a coordinated and orderly manner.

It is inevitable that the establishment of a Federal program necessarily carries with it certain uniform monitoring, reporting and other administrative requirements. This, however, is not to say that the Agency has made the judgment that all currently existing State programs would have to change radically in order to achieve EPA approval for delegation. Indeed, mindful of the instructions of the SWDA to minimize the disruption of existing effective State programs, EPA has gone to some lengths to avoid any requirement which would force any State to seek new legislation or to seek changes in existing regulations. While it is clear that there are variations in existing State programs to control underground injection, and that these regulations will have the effect of upgrading some of the State programs, it is EPA's expectation that many if not most State programs will be able to win EPA approval with only minimal changes. The Agency looks forward to working with State staffs to develop approvable programs as expeditiously as possible.

The House Committee Report also spoke to the congressional intent in adopting the amendments instructing EPA not to set requirements which would interfere with or impede oil and gas production (H.R. Report #93–1185, p. 31):

> "This amendment prohibits regulations for State UIC programs from prescribing requirements which would interfere with production of oil or natural gas or disposal of by-products associated with such production, except that such requirements are authorized to be prescribed if essential to assure that underground sources of drinking water will not be endangered by such activity.
>
> The Committee's intent in adopting this amendment was not to require EPA to bear an impossible burden of proof as a condition of promulgation of any such regulation. Rather, the Committee sought to assure that constraints on energy production activities would be kept as limited in scope as possible while still assuring the safety of present and potential sources of drinking water. Similar provisions were adopted with respect to EPA regulations which are to be promulgated when a State fails to adopt an approvable underground injection control program.
>
> In deciding what is an "essential" requirement, the Committee intends that the types of measures referred to in the Administrator's Decision Statement Number 5 and those referred to in this report be considered to be "essential" unless the contrary could be demonstrated with respect to a specific well or injection. Moreover, in using the works "interfere with or impede" the Committee did not intend to include every regulatory requirement which would necessitate the expenditures of time, money, or effort. Rather, the Committee intended to refer to those requirements which could stop or substantially delay production of oil or natural gas."

Thus, while these UIC regulations may create additional requirements and impose additional economic costs on oil and gas producers, and while they may result in the closure of certain marginal wells, the Agency is not persuaded that these regulations would result in a substantial delay of oil or natural gas production in the meaning of the Congressional intent.

Finally, the Agency finds little merit in the arguments that it has failed to demonstrate the necessary for the UIC regulations because it has not cited numerous instances of damage to underground sources of drinking water. It should be noted that in the basis for concern expressed in the House Committee Report (quoted earlier in this Preamble) Congress had clearly

concluded that the underground injection of contaminants is an increasing problem. Numerous instructions to the Agency in the House Report No. 93–1185 would seem to indicate that the Congress was fully aware that it was enacting a preventive statute which was aimed at preventing the contamination of the Nation's ground water resources, rather than at cleaning up after the damage had occurred. As one example of this, it is interesting to note the discussion of the definition of endangering drinking water sources (H.R. Report 93–1185, page 32):

"The Committee was concerned that its definition of 'endangering drinking water sources' also be construed liberally * * * The definition would be met if the injected material were not completely contained within the well, if it may enter either a present or potential drinking water source, and if it (or some form into which it might be converted) may pose a threat to human health or render the water unfit for human consumption. In this connection, it is important to note that actual contamination of drinking water is not a prerequisite either for the establishment of the regulations or for the enforcement thereof."

Furthermore, the Agency is mindful of the fact that Section 1421(b)(1)(A) of the SDWA specifies that once a State UIC program becomes established all underground injection is considered unlawful unless authorized by the State's UIC program.

Thus, the Agency did not conduct field work to document a national file of every case of contamination by a Class II injection practice. Nor did it try to establish the percentage of the Nation's ground water which has been contaminated by specific types of injection well practices. The Agency does acknowledge a responsibility, however, not to regulate needlessly or to force the expenditure of national rersources for frivolous purposes. Therefore, the Agency did review court cases and other available material to establish that the injection practices in Class II and the other classes do have a potential for contaminating underground sources of drinking water. We believe that documenting the potential for contamination does satisfy the legal standard imposed upon the Agency by the SDWA.

B. *Test of Endangerment.* The definition of the term "endangerment" has been one of the more commented upon sections of the UIC regulations. The original 1976 proposal of the UIC regulaltions followed the language of the SDWA. Section 1421(d)(2) of the Act states:

"Underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons."

The term "contaminant" is defined in section 1401(6) as "any physical, chemical, biological or radiological substance or matter in water."

The 1976 proposal, therefore, offered the following definition:

"Underground injection endangers underground drinking water sources if (1) such injection may make it necessary for a public water system using an underground drinking water source to increase treatment of the water, or (2) if such injection might make it necessary for a public water system which uses the source in the future to use more extensive treatment of the water than would otherwise have been necessary, or (3) if such injection may otherwise adversely affect the health of persons such as by adding a substance that would make water from the source unfit for human consumption." (Section 146,1 (x), 41 FR 36737).

Numerous adverse comments were received on this suggested definition. Many believed the definition to be confusing and vague, especially the third element relating to adverse effects on the health of persons. Other commenters held that EPA had simply restated the law in different words, and that the regulations should either use the statutory definition or one that could be applied with operational precision.

In response, the 1979 reproposal avoided a formal definition of "endangerment." Rather, it attempted an operational test that could be used with some operational significance. As the Preamble discussion pointed out (44 FR 23740):

"The test in these reproposed regulations is whether injection operations will cause the migration of injected or formation fluids into an underground source of drinking water. If injection into a well can cause such migration, the owner/operator must take appropriate action to eliminate the fluid migration."

The "no migration" standard was applicable to wells in Classes I–III, which were to achieve it through the use of sound engineering practices. The proposed ban/phase out for Class IV wells was also consistent with this standard. Since no technological requirements could ensure the absence of migration from wells designed to inject into or above USDWs, this practice was to be discontinued.

The proposal recognized two exceptions to the standard. One was in the case of Class V wells. EPA had determined (and still believes) that too little is known about the practices grouped in this class to make them ripe for regulatory controls. At the same time, the Agency did want to emphasize the responsibility of the Director to take action in cases where Class V wells did pose a real problem.

The Agency believed that a more selective standard than "no migration" was appropriate to define such situations because many Class V wells, even beneficial practices such as aquifer recharge wells, are designed to inject into potential USDWs. As a consequence, § 146.53 (44 FR 23766) required the Director to act when he gained "knowledge of a Class V well which presents a significant risk to the health of persons * * *"

The other exception appeared in § 146.22(c) (33 FR 23762) which gave the Director discretion to relieve Class II wells in existing injection fields of the applicable casing and cementing requirements. One condition of granting relief was that the well injection "will not result in the migration of fluids into an underground source of drinking water so as to create a significant risk to the health of persons using the source of drinking water." This formulation was chosen because the Agency wanted to recognize the special nature of construction requirements for wells in existing injection fields. While the Agency did not believe it appropriate to grant an unconditional license to endanger USDWs, it did believe it appropriate to allow additional scope in this instance in keeping with the proviso of the SDWA to avoid interfering with or impeding oil or gas production.

Commenters agreed that the proposed scheme was less vague than the earlier definition. However, several commenters now argued that the definition was too broad and that the term "migration" must be restricted in some fashion. Others were concerned because the definition seems to include displacement through underground hydraulic connections and argued that such migration was hard to anticipate, monitor, and, in some cases, control. Some commenters suggested that the term "migration" should be modified to some term such as "harmful migration", or "migration in harmful quantities." Others urged the use of such terms as "detectable migration" or suggested the use of ambient water quality standards broader than the parameters controlled in the National Interim Primary Drinking Water Standards. Still others questioned the appropriateness of departing from the language of section 1421(d)(2) to establish less restrictive standards for

Class V and the casing and cementing requirement in Class II.

EPA appreciates these suggestions but does not believe that they would improve the usefulness of the test. The use of a broader set of water quality standards or such modifiers as "harmful" would reintroduce the unworkability of the definition that was offered in the original proposal. The use of the term "detectable" would be redundant because, by definition, a migration into underground sources of drinking water could only be ascertained if it can be measured or detected. Finally, the lateral displacement of formation fluids is one of the pathways of contamination of concern in these regulations and EPA fully intended to bring it within the scope of this definition.

Consequently, the final regulations retain the "no migration" standard for Classes I–III, although it is now stated as "movement of fluids" or "movement of injection or formation fluids." (40 CFR 122.34). The Agency intends no substantive change through the substitution of "movement" for "migration." The two terms are considered synonymous and are used interchangeably in these regulations. The Agency does not believe that it is an overly protective standard. It does not require total containment; only that any leak or displacement not reach any USDW. It has the merit of being measurable and can be achieved through the use of readily available engineering technology which many injectors already apply.

Similarly, the "significant risk" standard has been retained in § 146.22(c). The Agency still believes that this is an appropriate condition for granting relief from the Class II casing and cementing requirements.

The Agency has decided to review the ban/phase out for some Class IV wells, while retaining this approach for those injecting into USDWs. The applicable standard is one of the questions in the further consideration of certain Class IV requirements. This subject is discussed more fully below.

In the case of Class V wells, the Agency has decided to establish a standard more closely in conformance with the statutory language. 40 CFR 122.34 (c) and (d) now require the Director to act if he learns that a Class V well "may cause a violation of primary drinking water regulations" or "may be otherwise adversely affecting the health of persons." These are not deemed to be more stringent or more inclusive standards. The Agency has not reconsidered its judgment that Class V wells are not ripe for regulatory controls, and enforcemnt action by the Director is not expected to become the rule rather than the exception it was intended to be under the Class V regulatory scheme. The Agency has decided that the use of statutory language is more appropriate in this case than a standard based on "significant risk."

The explicit authority to apply permits to Class V wells is new. Again, this is not intended to make the Class V requirements more stringent. The Agency, however, realized that the reproposed regulations had failed to provide the Director with any mechanism for applying controls in the cases where action needs to be taken with regard to a Class V injector to apply for a permit is intended to remedy this oversight.

C. Aquifer Restoration vs. Protective Action. A number of commenters urged the Agency to establish explicit requirements in the regulations that would force owners or operators of wells to take action to restore the quality of an aquifer under appropriate circumstances. The Agency has carefully considered these suggestions and has chosen not to establish explicit requirements for the following reasons.

Aquifer restoration has been tried on a pilot scale in shallow aquifers in connection with certain solution mining operations. Our review of the outcome of these pilot projects persuaded the Agency that full scale attempts at aquifer restoration could be very expensive with uncertain outcomes. Certainly in cases where solution mining is accompanied by an expected subsidence or catastrophic collapse in the overlying strata, the potential benefits of an aquifer resoration attempt are questionable.

The Agency also hesitates to impose restoration requirements because it interprets the mandate of the SDWA to be a preventive one. We believe that the main thrust of these regulations should be the prevention of further contamination rather than the restoration of aquifers that may already be damaged. The Agency is very much concerned that such requirements may divert scarce resources, both Federal and State, from the task of controlling underground injection which is the mandate under the Act.

At the same time it is not the intention of these regulations to preclude the Director from requiring the restoration of aquifers if such action is appropriate in particular cases. In establishing their UIC programs, the States are free to set more stringent requirements than the minimum requirements in these regulations. In addition, new § 146.10(d) requires the owner or operator of a Class III well to submit a plan of abandonment which must demonstrate that no migration from the mining zone into underground sources of drinking water will occur after abandonment. In setting abandonment requirements, the Director is given the discretion to set such aquifer clean up and monitoring requirements as he deems necessary to insure that the abandonment plan will be effective. The Agency will continue to assess the development of technology in this area and may establish additional appropriate requirements in the future.

D. Performance Standards vs. Technical Requirements. Many commenters criticized EPA for over-regulating by attempting to set technical requirements. They urged that EPA establish the objectives that it wants to achieve and allow discretion to the State Director and the injector in achieving those objectives. At the same time, many of the requirements were critized as being too vague and allowing too much undirected discretion to the permitting authority. Such commenters urged EPA to specify more clearly precisely what the standards are.

As these conflicting comments demonstrate, the tension between performance standards and technical requirements is an inherent problem in attempting to write national regulations in a highly technical area. Supporters of performance standards argued that they are an efficient means of regulating because they allow the owner or operator to choose how he will come into compliance. This, it is argued, tends to foster the development of new technology rather than stifling it and allows the most efficient means of coming into compliance to be applied in a particular instance.

Supporters of technical requirements argue that performance standards become almost impossible to enforce. Determining compliance or lack of compliance with the objectives of the regulations becomes a matter of long, drawn-out, highly technical arguments among technical experts. Further, it is argued that both in fairness to the regulated community, and in order to make the regulations enforceable, the regulations have a responsibility to spell out clear-cut requirements that the owner or operator understands and against which compliance or the lack of it can be measured.

Precisely because a great deal is still unknown about the movement of fluids below the surface, and because the monitoring of interactions is both difficult and uncertain, the approach of the UIC regulations has been to

translate the mandate of the SDWA into straight forward "good engineering" practices such as mechanical integrity of the tubular goods and the absence of man-made communication between the injection zone and higher strata. The presumption of the regulations is that as long as an owner or operator is in compliance with the technical requirements of "good engineering" practices, endangerment of nearby underground sources of drinking water will have been avoided. In cases where migration into underground sources of drinking water still occurs, even though the technical requirements have been complied with, the Director may impose additional requirements. In general, discretion in these regulations has been allowed where it seemed appropriate and possible to do so. On balance, this still seems the best approach to the Agency and it has been retained in the regulations.

E. Permitting Sequence. Many commenters pointed out an inconsistency between proposed 40 CFR Part 122 and 40 CFR Part 146 with respect to just when in the life cycle of a well a permit had to be obtained. A more important point of confusion was that the regulations seemed to require that the Director, prior to issuing the permit, review certain information which, at least in some cases, could not be produced without injecting into the well, even though the regulations seemed to prohibit injection without a permit.

The Agency agrees that the proposed regulations were not clear on this point and has now clarified the permitting sequence. The regulations now make clear that the requirement is for a single multi-phase permit similar to the current practice in a number of States, e.g., Michigan. In the case of a new well, the owner or operator must apply for a permit, which may be issued to him after appropriate public comment and hearings, before any work to drill or convert a well begins (see 40 CFR 122.33 and 122.38(b)). The permit is to have three phases: construction, testing and stimulation; operation; and abandonment. The applicant's plans for the construction and preparation of the well, as approved by the Director, will be incorporated into the permit as permit conditions. Should the plans change in any material way, the permittee must notify the Director and obtain his concurrence to the changes. Such modifications are considered to be minor modifications and can be approved administratively without the requirement for public hearing and comment.

It is the responsibility of the owner or operator to notify the Director of the completion of each phase and to obtain the Director's written or oral permission to proceed with the next phase (see 40 CFR 122.41(c), 122.42 (a) and (f), and 146.10). The permittee must provide the Director a 13 day opportunity to conduct a physical inspection of the well before putting the well into operation. Conditions for the operation of the well will be established by the Director as part of his notification to the owner or operator that he may proceed with the next phase. The Sections of Part 146 specifying the information to be submitted by the applicant and to be considered by the Director have been modified to reflect this clarified scheme.

The owner or operator of an existing well must submit his application at the time he is required to do so by the Director in accordance with the Director's plan for re-issuing permits submitted as part of the State program to EPA for approval. The permit will apply to the operating and abandonment phases of the well's life, but may incorporate compliance schedules according to which the injector must perform such corrective actions as the Director may require.

The Agency believes there are several advantages to this approach, not the least of which is that it will minimize the changes required in the current procedures of most States. By placing the permitting decision at the beginning of the process, it assures the applicant of a decision before any major investment has been made. Since the approval to proceed to the next phase can be handled administratively, it avoids any major delays once the project has been initiated. Finally, it provides a greater degree of environmental protection by clarifying the authority of the Director to supervise the construction and testing of the well in addition to its operation and abandonment.

F. Coordination of Authorities Under SDWA, RCRA and CWA. One of the questions addressed in the consolidation of the Agency's major permit programs was the coordination of overlapping authorities over well injection. Section 3005 of RCRA states that once the Hazardous Waste Management program is established, hazardous waste may only be disposed of (including injected) in a site approved under the authority of RCRA. At the same time, Section 1421 of SDWA states that once a UIC program is established for a State, any well injection in the State is prohibited unless authorized under its UIC program. Since there are differences between SDWA and RCRA, these parallel statutory sections could subject the operator of an injection well used to dispose of hazardous waste to duplicative and possibly conflicting requirements. In keeping with its intention of reducing administrative burdens on the regulated community, the Agency offered the following resolution in the 1979 proposal of the Consolidated Permit regulations. The surface management of hazardous waste would be regulated under RCRA while injection wells would be regulated under the SDWA. The separation point would be at the cut-off valve at the well-head. A facility would have to obtain authorization under SDWA to operate the well itself. Any attendant surface facilities used to manage hazardous waste would have to be permitted under RCRA. The rationale for this proposed method of regulation was twofold: First, the technical differences between surface disposal techniques and well injection argue that the two sets of practices are appropriately regulated through differing technical requirements; second, the proposal avoided the imposition of duplicative procedural requirements on the operator of the well.

Three major comments were received on this proposed course of action. Two of them agreed in general with EPA's decision as long as the owner or operator of the well would have to complete the manifest-keeping requirements under RCRA. This was, of course, one of the conditions specified in proposed 40 CFR 122.44 and 40 CFR 146.09. The third commenter objected strongly arguing that: (1) The language of Section 3005(a) of RCRA does not allow the disposal of hazardous waste in any facility that is not permitted under RCRA; and (2) the disposal of hazardous waste should be regulated under RCRA because that Act provides a greater level of protection to the environment.

EPA has reviewed these comments with great care and rejects the general argument that the level of protection afforded the environment from the potential effects of underground injection would necessarily be greater under RCRA than under SDWA. While it is true that RCRA authorizes the Agency to protect human health and the environment from the impacts of hazardous waste disposal, the scope of this mandate is not directly relevant to well injection. The major concern from the injection of fluids is the potential danger to underground sources of drinking water, and the Agency believes it has adequate authority under SDWA to protect such sources from the effects of well injection. Futhermore, because of

technical differences in the practices, the requirements which are appropriate to surface disposal methods are not in many cases, appropriate for well injection. Indeed, the Agency would promulgate essentially the same technical requirements to regulate the well injection of hazardous wastes whether it did so under SDWA or RCRA.

In response to comments, however, the Agency has changed its approach to coordinating RCRA and SDWA authorities in three ways. First, under SDWA no enforceable requirements will apply to operators of injection wells in a State until the UIC program for that State is effective. Because of the statutory scheme of SDWA, State programs will not be established until one to two years after the minimum requirements in 40 CFR Part 122 have been promulgated. EPA agrees that, under the proposed regulatory approach, the SDWA would, therefore, not have provided a level of control equivalent to RCRA over wells used to inject hazardous waste during the interim period. Consequently, the final 40 CFR 122.23 requires that owners or operators of Class I and IV wells obtain interim status under RCRA. Certain standards for interim status are contained in 40 CFR Part 265 Subpart R which has been made applicable to such injectors. Additional standards have been proposed (see 45 FR 33280) for future inclusion in Part 265. Injectors of hazardous waste will ultimately be regulated under the SDWA. However, prior to the time a State UIC program is effective, hazardous waste injection wells may be permitted under RCRA (see 40 CFR 122.30) for a period not to exceed two years.

Second, in contrast to the proposal, injection wells will now be authorized under both RCRA and SDWA once the applicable State UIC program becomes effective. A permit by rule under RCRA (see 40 CFR 122.26) will authorize the disposal of hazardous waste into an injection well if the well has been properly authorized under SDWA. This final resolution was adopted because it satisfies the statutory language of both Acts. At the same time, the goal of minimizing procedural burdens on the regulated community will be maintained. As a practical matter the owner or operator of a well used to inject hazardous waste will still only have to obtain authorization and comply with requirements applicable to him under the UIC program. Compliance with applicable UIC requirements will be deemed to satisfy RCRA requirements as well.

A final point concerns the delegation of interim status authority to States. States will be given the option to choose whether to assume interim control over hazardous waste injection wells under RCRA and then convert to control under SDWA. Alternatively, they may leave interim regulation of such wells with EPA and accept delegation only at the time their UIC program becomes effective. If a State chooses the former method, it will be required to assume responsibility under RCRA through the same agency that will ultimately exercise the responsibility under the SDWA.

Other changes have also been made in the regulatory scheme for Class IV wells. They are discussed later in this preamble.

Injection wells, with the exception of Class II, could also be regulated either under the Clean Water Act (CWA) or the SDWA. More specifically the CWA requires that in cases where the National Pollutants Discharge Elimination permitting system (NPDES) is delegated to States, the States must have the legal authority to also control the disposal of pollutants into injection wells. The proposed Consolidated Permit regulations in § 123.74 required State NPDES permit programs to have the authority to issue permits to control the disposal of pollutants into wells.

Such a requirement could conceivably have some undesirable results. To the extent that there are differences between the CWA and the SDWA, such a requirement could, for example, require a State to develop a UIC program which meets the requirements of the SDWA and then to develop separate authorities to control well injection that meet the requirements of the CWA. In addition, this section could be read to imply that the UIC program and the NPDES program could only be delegated in concert.

In order to resolve these difficulties, final Section 40 CFR 123.72 now requires that State law provide authority to issue the permits in question and specifies that an approved UIC program satisfies this requirement for the NPDES program.

II. Major Programs Concepts

A. Well Classification. In the proposed 40 CFR Parts 122 and 146.05, the Agency proposed a revised scheme for classifying injection wells and requested comments on its appropriateness. In general, commenters agreed that this was a workable classification system. A number of commenters, however, suggested the need for further clarification. Section 146.05 of these regulations attempts to resolve the points that were raised.

First, a number of commenters pointed out that in the case of Class I and Class IV wells, part of the definition of the well involved the relationship of the well to the nearest drinking water source, without, however, specifying any distance or other limitation. The applicable definitions now specify that Class I wells must inject below the deepest formation which, within a quarter of a mile of the well bore, contains an underground source of drinking water. Conversely, Class IV wells are those that inject into or above a stratum which, within a quarter of a mile of the well, contains an underground source of drinking water. As a basis for this clarification, the Agency relied on the concept of the area of review and conformed these definitions to the minimum of one-quarter mile to be used when the area is established by the use of a fixed radius.

Second, many commenters were concerned about sand backfill wells and the possibility that, because of the nature of the injected materials, these wells could come under the classification of hazardous wastes under Class IV. This was not the result intended by the Agency. The final regulations now specify that sand backfill wells are to be considered Class V. They are to be assessed for their environmental impact and future regulations may be applied to them.

Third, some commenters suggested that the proposed regulations left some confusion over the status of non-residential septic systems. Single-family domestic sewage disposal systems are not covered under the UIC program. Multiple dwelling and industrial sewage disposal systems are generally included in Class V. Those that are used to dispose of hazardous waste fall under Class IV.

Fourth, a number of commenters suggested that disposal wells handling blowdown water discharges from gas refinery plants and similar wastes be treated not as Class I but as Class II wells. Given the nature of these operations and the chemical compositon of the injection fluids, the Agency has decided that these operations would be more appropriately regulated under Class I.

Fifth, some commenters expressed confusion over the status of injection wells used to store fluids which are used in the recovery of stored hydrocarbons. Section 146.05 clarifies that such wells are now to be treated not as salt water disposal wells, but as Class II hydrocarbon storage wells.

Sixth, during the comment period, EPA was made aware that hazardous waste may in some cases be injected in

situations other than into, through or above an USDW. Because of the definition of Class IV, these injections would, under the proposed regulations, have fallen into Class V. Commenters argued that the injection of hazardous waste merits stricter regulation than the requirements of Class V even if it is not into, through or above an USDW. The Agency agrees with this view, especially because it seeks to make the control of hazardous waste disposal under RCRA and SDWA comparable. Therefore, the injection of hazardous waste other than through Class IV wells is now included in Class I (see 40 CFR 122.32(a)).

Seventh, the proposed regulations included "nuclear" storage and disposal wells in Class I (see proposed 40 CFR 122.34, 44 FR 34282). The definition of the term "solid waste" (and therefore "hazardous waste") under RCRA may include certain kinds of radioactive waste, but specifically excludes source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954, as amended. Since the SDWA does not contain a similar limitation, the Agency proposed to include the injection of such material in Class I. Few commenters addressed this aspect of the proposal, although some objected to granting States authority over these sources. The President on February 12, 1980, issued an Executive Order outlining a program to arrive at a comprehensive radioactive waste management program. Until this program is complete, and EPA has had an opportunity for full consultations with the Nuclear Regulatory Commission, the Department of Energy, and other agencies with responsibilities potentially affecting radioactive wastes, it would be premature for EPA to issue regulations concerning the disposal of radioactive wastes into Class I wells. Moreover, EPA wishes to coordinate any regulations governing sand backfill wells with regulatory measures it may undertake under the Uranium Mill Tailings Act. Accordingly, EPA has modified the classification of wells so that wells disposing of radioactive wastes below strata containing a USDW will be Class V wells.

However, the disposal of radioactive wastes into or above USDWs is an environmentally undesirable practice. Therefore, EPA has added a definition of "radioactive waste" in § 122.3 which clarifies that the term "nuclear" waste used in the proposal was intended to cover not only the radioactive wastes which are hazardous wastes under RCRA but also fission by-products and similar wastes covered under the Atomic Energy Act of 1954. The disposal of all such wastes into or above USDWs is included in Class IV and will be regulated according to the scheme promulgated for Class IV wells: those Class IV wells injecting into a USDW are prohibited; requirements for other Class IV wells will be promulgated in the fall of this year. (See the discussion of Class IV requirements below.)

Section 122.31(d) now includes specific inclusions and exclusions from the coverage of the UIC program. Notes have also been added to § 146.05 for the convenience of the reader.

B. Underground Sources of Drinking Water. Since the original proposal of the UIC regulations in 1976, an underground source of drinking water has been defined as an aquifer or its portion which either currently provides water for human consumption or is capable of yielding water containing fewer than 10,000 mg/1 of total dissolved solids (TDS). A number of commenters again objected to the reproposal of 1979 setting the standard at 10,000 mg/1 of TDS, and offered a number of alternative concentration levels. EPA has carefully reviewed these alternative suggestions and has once more decided to retain the standard of 10,000 mg/1 of TDS. None of the alternative concentrations have any superior justification in terms of current State practice, human health, or technological considerations. In the absence of any overriding argument to the contrary, the Agency will follow the standard in the House Committee Report accompanying the SDWA.

A number of other comments were offered on the scheme for designating underground sources of drinking water. Some pointed out an apparent conflict between Part 122 and Part 146, in that the former seemed to require the State Director to designate underground sources of drinking water while the latter seemed to require him to designate aquifers which were exempted from protection. Others urged the Agency to clarify the procedure for making the initial designation and the procedures whereby designation could be changed in the future. Still others pointed out that the use in the exemptions of such terms as "economically or technologically impractical" were imprecise and ought to be defined further. Finally, some argued that the exemption provided for "oil or mineral producing" aquifers seemed to imply that only areas actively being worked could receive such an exemption. They argued that the future development of mining sites could be hampered because of the uncertainty of whether or not the mining site could receive an exemption from the definition of underground source of drinking water. Therefore, they urged the use of the term "bearing" so that prospective mining sites would be assured of receiving a permit to operate, and thereby enhance their ability to obtain financing.

EPA agrees with some of these comments and disagrees with others. The final regulations attempt to clarify the definition of "underground source of drinking water" as well as the process for designation in the following way. The terms "underground source of drinking water" and "exempted aquifer" are defined in § 122.3. "Underground sources of drinking water" are aquifers or their portions which currently provide water for human consumption or which are capable of yielding water containing fewer than 10,000 mg/1 of TDS. Under § 122.35, the Director, as part of the State program he submits for approval to EPA, may identify those aquifers or aquifer portions which will be considered as underground sources of drinking water. This identification may be done by definition, description, illustration, or other means. The reason for this is to relieve the Director of the requirement for extensive underground exploration and mapping, or of supplying a level of detail with his State program submission which will force a modificaion of the State program for every minor modification in the depth or extent of the fresh water zone. As stated in § 122.31(d), an aquifer is an USDW if it fits the definition even if it has not been affirmatively identified by the Director.

An "exempted aquifer" is an aquifer or its portion which would otherwise meet the standard for an USDW but has been designated as "exempted" by the Director in conformance with § 146.04. Section 146.04 states that a Director may designate as an exempted aquifer an aquifer or aquifer portion which does not already provide water for human consumption but is capable of yielding water with a concentration of fewer than 10,000 mg/1 of TDS, if the aquifer or its portion is:

(1) Mineral, hydrocarbon, or geothermal energy producing;

(2) Situated at a depth of location which makes recovery of water for drinking water purposes economically or technologically impractical;

(3) So contaminated that it would be economically or technologically impractical to render it fit for human consumption; or

(4) Located over a Class III mining area subject to subsidence or catastrophic collapse.

The first three of these conditions have changed only in substituting the broader term "hydrocarbon" for "oil" in the first proposed criterion. The Agency has declined to change the term "producing" to "bearing" in the first condition because it did not want to open the possibility of wholesale exemption of aquifers, over large areas of the country, which become identified as being capable of producing one or another mineral. Similarly, the Agency has chosen not to define further the term "economically or technologically impractical." After considering the alternatives, the Agency decided it was more appropriate to leave the determination of what is or is not economically or technologically impractical to the discretion of the Director in the particular case.

The fourth exemption is new. It is an attempt to respond to those commenters who correctly pointed out that certain Class III mining operations necessarily involve the subsidence or collapse of strata above the injection zone. In such cases, the probability of harm to the overlying aquifers is substantial once operations are underway. The decision to protect these aquifers is more appropriately made at the time the mining operation is permitted.

In cases where the Director chooses to exempt an aquifer, he is required to submit not only detailed maps, but also sufficient justification in support of the exemption.

The Director may exempt aquifers as part of the State program he submits to EPA for approval. Therefore, the designations, by the nature of the process, are subject to public hearing and comment as well as the review and approval of EPA. The Director is free to change the designations or add to them at a later date. Such a change, however, would constitute a major modification of the approved State program and, as a major modification, is subject to public hearing and comment, as well as EPA review and approval.

C. Area of Review and Corrective Action. Most of the comments received on the revised area of review/corrective action concept contained in the reproposed 40 CFR Part 146 were generally supportive, although a number of specific suggestions were made. *First,* a number of commenters pointed out that the equation provided in the proposed § 146.06 was applicable only in certain circumstances. EPA agrees, but notes that in proposed § 146.06(c), the alternative calls only for the computation of the zone of endangering influence based upon certain parameters. The modified form of the equation provided in that section was illustrative and for the convenience of the reader. It was not intended to represent the only acceptable equation to be used in all cases.

Second, a number of commenters suggested that the applicant for a permit be given a voice in the decision of how the area of review would be determined for his well or field. EPA agrees and has added to the regulations giving the Director discretion to consult the applicant in this regard (§ 146.06). *Third,* some commenters suggested that the one-quarter mile radius be made an absolute minimum regardless of whether the zone of endangering influence was determined as fixed distance or through computation. EPA disagrees with this suggestion. In cases where the zone of endangering influence is actually less than a quarter of a mile, such a requirement would force the applicant to expend resources and do work which may not be justified by the expected benefits. *Finally,* some commenters suggested that the area of review be drawn from the edge of a field or project rather than the individual well. EPA agrees. The concept was included in the language of the proposed § 146.06(c) and has been retained in the final requirement.

Two comments were made with regard to the proposed corrective action requirement. The first suggestion was that the text of the proposed regulations seems to imply that it is up to the applicant to collect the information on the number of wells penetrating the injection zone within the area of review. The argument is that such information is kept by the State and, therefore, the requirement should be for the State, rather than for the applicant, to gather this information. The Agency agrees only in part. While it is correct that in many cases this information is in the files of the State, and, therefore, simplicity would suggest that the State should make use of this information in the review of the permit application, the Agency believes it important that the ultimate burden for providing the information necessary for an adequate review of a permit application should rest with the applicant and should not be transferred to the permitting authority. Therefore, the language of the final regulations makes it possible for the State to supply this information when, in the judgment of the Director, it is appropriate to do so. However, the final regulations do not explicitly relieve the applicant of the responsibility for making such information available when the Director deems it appropriate.

Another area of comment concerned the possible interpretation that in requiring corrective action on wells that penetrate the injection zone within the area of review, the Director may be put in a position of requiring the applicant to go onto the property of others, or to take corrective action on the property of others in order to meet the permit conditions. EPA agrees that it is inappropriate for these regulations to require an applicant to perform actions which may not be within his legal ability, as a condition or precondition of obtaining a permit. As a consequence, the corrective action requirement has been revised (§ 122.44) to provide the Director and the applicant with three options.

First, if he can arrange it with the neighboring owners and operators, the applicant may, before he begins to inject, take the corrective action prescribed by the Director and then inject at his intended injection pressure.

Second, the Director may issue a permit with a reduced injection pressure calculated so that the potential zone of endangering influence will be no bigger than the area under the control of the applicant in which the applicant can take the appropriate corrective action.

Third, the permit can be issued with the requested injection pressure but with the condition that the owner or operator must operate at a lesser pressure until such a time that he takes the corrective action required to allow a more extensive zone of endangering influence. In arriving at this resolution, EPA did not agree with suggestions that the State use its authority to force the owner or operator of the "bad" well to repair it. The Agency believes that it is not appropriate to use the authority of the State to force one individual, without his agreement, to incur expenses and effort which benefit another party. In addition, abandoned wells in the area of review also may have to be fixed. In many cases, it may not be possible to locate a responsible party.

D. Mechanical Integrity. Proposed § 146.08 defined mechanical integrity as having two parts: (1) The absence of a significant leak in the casing, tubing or packer; and (2) the absence of significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore. The proposal specified that the absence of significant leaks was to be established through the use of eight listed tests. The absence of significant fluid movement could be demonstrated either through well records demonstrating the presence of adequate cement or the result of a cement bond log, sonic log, temperature log, density log, or dual neutron log. The

proposed section further specified that the Director may allow the use of a test other than those listed upon the written approval of the Administator of EPA. The owner or operator of the well was to demonstrate the mechanical integrity of his injection well as a condition of authorization and at least every 5 years thereafter.

Virtually all aspects of this requirement received public comment. However, there does not appear to be a clear consensus in the thrust of the suggestions offered the Agency. Some commenters argued that a demonstration of mechanical integrity every 5 years is too frequent. Others argued that it is not frequent enough. Some questioned the reliability of cementing records, while others supported the use of such records and urged the Agency to go beyond its proposal by allowing the demonstration of mechanical integrity through the historical absence of contamination. Some commenters urged the Agency to rely on annular pressure tests; others disagreed. Some argued that the Director be given the discretion to specify which test he found acceptable as a demonstration of mechanical integrity. Some objected to the proviso that the Administrator approve the use of tests other than those listed in § 146.08. Others urged that such additional tests as the Director approves should be listed in the **Federal Register** for the use of others.

The majority of commenters did seem to agree in three areas. Most commenters urged the elimination of the words which seemed to require the use of more than one test to demonstrate the absence of significant leaks. Many commenters also found some fault with one or more of the tests specified by EPA in this section. Finally, in response to a request for comments in the preamble, many commenters supported the idea of a sampling approach to mechanical integrity rather than a requirement for universal demonstration.

EPA has carefully considered these comments and requested its consultant to conduct further technical analyses. Based on this work, EPA has decided to make the following changes in the final version of § 146.08.

First, EPA agrees that in order to demonstrate the absence of significant leaks in the casing, tubing, or packer of a well, any one of the specified tests is sufficient and has, therefore, eliminated the term "some combination."

Second, the analysis performed for us by Geraghty and Miller, Inc. suggested that the eight tests proposed as methods for demonstrating the absence of significant leaks were either incorrectly cited, redundant, or not particularly reliable in demonstrating the absence of leaks. Consequently, the final regulations retain only two of the eight tests listed in paragraph (b) of the proposed § 146.08. These are the monitoring of annulus pressure and pressure tests with fluid or gas.

Third, with regard to the listed tests to establish the absence of significant fluid movement in the well bore, the cement bond log, sonic log, density log, and dual neutron log have been eliminated, leaving temperature log or noise log as the specified tests. The basis for this decision is again the analysis conducted by the Agency's consultant.

Fourth, the requirement that the Administrator approve the use of tests other than those specified in § 146.08 has been retained, but in a different form. The use of alternative tests to demonstrate mechanical integrity is considered to be a major modification of the State program and must be treated as such under § 123.13. Two further points are worth discussing regarding mechanical integrity. The public comments and the work of our own consultant have raised some questions with regard to the reliability of historical well records to demonstrate the absence of fluid movement in the well bore. As a result, well records are no longer considered an acceptable method of demonstrating this aspect of mechanical integrity in the case of Class I and III wells. The use of well records has been retained for Class II wells because of the large number of wells in the Class and the statutory provision not to unduly interfere with or impede oil or natural gas production. However, the requirements for Class II wells will be subject to a mid-course evaluation. As one part of this evaluation, a sample of Class II wells, for which well records were used to demonstrate the absence of significant fluid movement in the well bore, will be required to perform the specified tests as well. This procedure will provide a comprehensive assessment of the reliability of well records and will provide a factual basis for future Agency decisions on whether to expand or eliminate the acceptability of well records to demonstrate mechanical integrity.

Finally, the preamble to the reproposed Part 146 (44 FR 23743–4) solicited comment on the possibility of requiring only a sample of wells, rather than all, to demonstrate mechanical integrity. Although many commenters supported this concept, the final regulations do not include any sampling approaches to the demonstration of mechanical integrity. Rather, the Agency decided to combine a test of the effectiveness of sampling with its decision to accept well records as a method for demonstrating the mechanical integrity only of Class II wells.

E. Area Permits. The 1979 version of the regulations proposed an area permit which would allow a number of wells of a similar purpose and construction under the control of a single owner or operator to be authorized by one permit. While most commenters approved this concept, they pointed out that the manner in which several sections of the proposal were worded seemed to imply that requirements would still have to be fulfilled on a well-by-well basis. One example of this was the information to be submitted in support of a permit application.

EPA agrees with this criticism and has clarified Part 146 throughout to make clear that a single permit for a number of wells can be applied for and obtained on an area basis. Section 122.39, dealing with area permits, has also been expanded to clarify the regulatory intent in this regard.

F. Logging and Testing Requirements. The sections of the 1979 proposal that received the most extensively adverse comments were the parallel requirements for Classes I, II, and III to conduct certain tests during the drilling and construction of wells and to report the information to the Director. Almost all commenters felt that specifying the actual logs and tests to be used was inappropriate, and, in most cases, overly inflexible. Upon consideration, the Agency agrees. These parallel sections for Classes I, II, and III have been changed. Final Part 146 requires deviation checks, but only for wells constructed with the use of pilot holes and reaming techniques. The Director is given discretion to specify the other logs and tests that may be required based upon the availability of similar data in the area of the drilling site, the construction plan and the need for additional information that may arise from time to time as the construction of the well progresses.

G. Control of Injection Pressures. The proposed regulations required the Director to establish limits on the injection pressure at the wellhead for Classes I, II, and III. In the case of Class I, the surface pressure was to be calculated so that the bottom hole pressure during injection did not propagate fractures in the injection zone and did not initiate fractures in the confining strata. For Class II, the surface pressure was to be calculated only so that the bottom hole pressure did not

initiate fractures in the confining strata. Because of the special nature of Class III operations, the injection pressure at the wellhead was to be controlled so as to prevent the migration of fluids into underground sources of drinking water.

Several commenters suggested that there be no restrictions on injection pressure. Others offered specific alternatives as to how injection pressure should be controlled and what it should be designed to prevent. In particular, representatives of the oil and gas industry argued that the wording of this requirement could cause the loss of oil reserves valued at approximately $60 billion nationwide.

Upon further consideration of this requirement, the Agency finds that the original intent of these requirements was appropriate. However, two points of clarification are appropriate to resolve the problem pointed out by the commenters. First, in the final Part 146 the terms "injection zone" and "confining zone" are defined to include a single formation, part of a formation, or a group of formations. The regulatory concern of the Agency is that between the underground source of drinking water to be protected and the injection zone, there be a relatively impermeable barrier which is not breached by the injection pressure. This barrier may be composed of a single formation or a group of formations. Secondly, the proposed regulations used the term "bottom hole pressure" inappropriately. Because the friction loss across the perforations of the casing, the injection pressure in the formation is not equal to the bottom hole pressure within the casing. The concern of the Agency is with the pressure in the formation, and the final regulations have been changed to require the calculation of pressure at the well-head so as to produce an acceptable pressure in the injection formation as opposed to the casing at the bottom of the hole.

III. Changes in Individual Well Class Requirements

A. Class I. In the original 1976 proposal, the Agency had suggested a 5-year term permit for all classes of wells regulated under the UIC program. In response to extensive comments, the 1979 reproposal substituted lifetime permits for all classes to be regulated by permits. To balance the authorization of these practices for their entire life, Part 122 established extensive review, modification, and revocation and reissuance requirements. Most commenters found these requirements to be confusing and believed them to be inappropriately extensive.

In the final Consolidated Permit regulations, the Agency decided to move in the direction of term permits. Hazardous Waste Management program permits under RCRA as well as Class I permits under UIC will be issued for a period not to exceed 10 years. There are several reasons for this decision. The fluids injected into Class I wells, in many cases, are expected to pose a high degree of risk for the environment. Therefore, a greater degree of regulation is considered appropriate. Furthermore, Class I wells are more likely to be the group of facilities that will require multiple EPA permits since many of them are used at industrial sites where hazardous waste may be generated and surface discharge of waste also occurs. Term permits for Class I wells will ease the difficulty of consolidating and integrating various EPA permits to the same owner or operator.

To balance the shorter permit term, the consolidated permit regulations now provide the permit holder greater security during the term of the permit by restricting the reasons for which the permit may be reviewed, modified or revoked.

B. Class II. In addition to the changes affecting Class II wells discussed above, several additional changes for Class II wells are reflected in the final Part 146 regulations. The first of these is a change in the casing and cementing requirements for existing wells. In the original proposal of 1976, the Agency had required that all injection wells must be cased and cemented to protect drinking water sources containing up to 3000 mg/l of TDS. A number of commenters pointed out to the Agency that such a requirement was impractical and onerous. Since there is a rough correlation between depth and the concentration of TDS in ground water, a requirement for casing and cementing to protect levels of TDS higher than previously protected essentially means that an injection well will have to be cased and cemented to a greater depth.

Based on analysis undertaken after the 1976 proposal, the Agency agreed with the commenters that in many, if not most cases, it is impossible to extend the casing in an existing well. While it is possible to add cement to a well, EPA's consultants estimated that the cost of such a requirement in existing Class II wells could run upwards of $20 billion. However, in existing injection fields, there was some question as to the environmental benefit of protecting aquifers which had not been protected previously.

As a consequence, in the 1979 reproposal, EPA included § 146.22(c). This section granted the Director the discretion not to apply the Class II casing and cementing requirements to new or existing wells in existing injection fields under three conditions: (1) That State regulations for the construction of injection wells existed prior to the State UIC programs; (2) that such requirements had been applied to the injection wells in question; and, (3) that the injection wells did not cause a significant risk to the health of persons using the impacted USDW.

EPA's intention in this section was to alleviate the casing and cementing burden for existing Class II injection wells. The Agency believed, however, that some restrictions on the discretion of the Director were appropriate. For example, the Agency did not want to condone every casing and cementing practice, regardless of its potential for contamination, or to force the Director to authorize every injection well even if it posed a significant risk to the health of persons.

Commenters on the 1979 reproposal maintained that such a grant of discretion to the Director, with its limitations, did not really solve the problem. A major concern seemed to be that a number of States do not or did not have applicable casing and cementing requirements which would satisfy the conditions of proposed § 146.22(c).

These final regulations have been changed to clarify the relief that the Agency intended to grant. Final § 146.22(c) states that the Director need not apply the casing and cementing requirements of Class II if: (1) An existing or newly converted injection well in an existing field is in compliance with whatever State requirements were applicable to that field at the time the well was constructed, and (2) the injection will not cause the movement of fluid into an USDW so as to create a significant risk to the health of persons.

Newly drilled injection wells in existing fields are to comply with the requirements the State applied to that field prior to the effective date of the UIC program (§ 146.22(d)), and may not create a significant risk to the health of persons. If a State had no requirements for casing and cementing, the Director, in accordance with § 146.22(e), is to file a plan as part of his State program application which describes the casing and cementing requirements he proposes to set for wells in existing fields. If EPA approves, the State program becomes effective, and those will be the requirements to which injection wells in existing fields must conform.

Class II injection wells in existing fields will, however, have to

demonstrate the integrity of such casing and cementing as they have.

The second change in Class II requirements concerns the conversion of wells, i.e., the practice of creating a new injection well by converting a well that had been drilled for other purposes. Many commenters pointed out that newly converted wells would have the same problems in meeting more extensive casing and cementing requirements as existing injection wells. Consequently, the application of the full Class II construction requirements to all new wells, including newly converted wells, was equivalent to prohibiting the practice.

The Agency agrees with these comments, and does not intend to prohibit the practice of converting existing wells. Consequently, newly converted wells have been included in final § 146.22(c) and (e). Whereas the proposed § 146.22(c) was limited to existing injection fields, the final relief applies to all existing fields, including those being converted to injection. Thus, the intended relief has been made available to converted wells also.

A third change concerns Class II reporting and monitoring requirements. A number of commenters pointed out that in many cases (particularly in the case of unitized enhanced recovery injection fields) monitoring is now conducted, but not on a well-by-well basis. The Agency has reviewed this question and has decided that no particular benefit is to be served by insisting on monitoring and reporting on an individual well basis, particularly since in many cases, such wells will be regulated under an area permit. Consequently, the final regulations now allow enhanced recovery injection wells to be monitored on a field basis, and the results of monitoring to be reported to the Director on the same basis.

Finally, in reviewing these regulations for promulgation, the Agency became aware of a potential problem resulting from the estimated time which might be consumed in processing permits for new wells. In many cases, the ability to produce from a new well may be contingent upon the availability of an injection well for disposing of the brine produced with the oil or gas. In existing fields, this is not expected to be a serious problem because disposal alternatives are expected to be available. However, in the case of wildcat explorations in new areas, fewer alternatives for disposal are expected to be available. Therefore, the production from a new well may have to be delayed until a permit for the construction and operation of a salt water disposal injection well is obtained. Based on our analysis, such delays could represent significant costs in terms of delayed oil and gas production.

To resolve this problem, § 122.40 of the consolidated permit regulation has been expanded. In addition to cases where imminent and substantial endangerment to human health exists, or cases in which a substantial and irretrievable loss of oil or gas resources will occur, a temporary authorization to construct and operate a salt water disposal well may be granted to avoid a substantial delay in oil or gas production. In such cases, an application for a permit must be filed, and the emergency authorization may be given until the Director acts upon the application.

C. Class III. In the preamble to the 1979 proposal of Part 146, the Agency gave notice that it had received extensive comments on the Class III requirements originally proposed in 1976. As the preamble noted, a number of the suggestions offered in response to the original proposals had been incorporated in the reproposal. However, as the preamble went on to state, (44 FR 23746) the Agency was continuing to evaluate alternatives for subcategorizing Class III requirements and was soliciting public comment on some additional fundamental changes. The public comments received on the 1979 reproposal urged the Agency to make some of these changes. The Agency agrees and has extensively revised the requirements for Class III.

Some of the following changes have already been discussed earlier in this preamble, but their impact on Class III is worth reviewing here. First of all, § 122.31(d)(2) of the final Consolidated Permit regulations lists as a specific exclusion, those wells which fall outside of the territorial waters of States. The rationale for this exclusion is that the Safe Drinking Water Act intended the UIC program to be a State and not a Federal program. When EPA promulgates and administers an UIC program, it does so in lieu of the State. Therefore, the Agency has judged it inappropriate to assert original Federal jurisdiction over offshore wells that operate beyond the territories of States. This exclusion exempts certain Class III operations from the coverage of these regulations.

A second important change is that the final § 146.04 now allows the Director to exempt from protection as underground sources of drinking water, those aquifers overlying the site of a Class III operation subject to subsidence or catastrophic collapse. This provision for exempting aquifers should be read together with final § 122.43 which states, that in cases where an injection well is not into, through, or above an underground source of drinking water, the Director may ease the conditions that he applies to a particular injection well or operation, provided that such eased requirements do not increase the risk of migration of fluids into underground sources of drinking water. This combination of provisions should make it possible to ease the burdens for Class III operations in a number of cases.

Third, one of the concerns of the comments on Class III was that the requirement that no new wells could begin to operate until they had been authorized by permit, could lead to a temporary disruption of operations while the permit was being processed. As in the reproposal, final § 122.37(a)(1) provides that existing Class III operations may be authorized under a rule until a permit is applied for and granted. However, the Section now also specifies that a Class III operator may continue normal operation, including the construction and operation of new wells, under the rule as long as he is in compliance with all applicable requirements.

Fourth, commenters were also concerned about the requirement that even under an area permit the prior approval of the Director had to be obtained before a new well could be placed into operation. As discussed above, the conditions for an area permit have been clarified in general. In addition, final § 122.39(c) now specifies that new wells may be constructed and operated under an area permit without prior approval as long as the new wells are in compliance with permit conditions, the owner or operator notifies the Director according to procedures established in the permit, and the cumulative effect of new well construction has been evaluated by the Director previously. The Agency believes that the four changes listed above should help to resolve many of the problems pointed out in the public comments.

One of the major areas on which public comment was requested in the preamble to the 1979 reproposal, was whether or not the technical requirements for Class III wells should be subcategorized. The commenters on the regulations overwhelmingly favored this course of action. However, the comments were less helpful in suggesting practical ways in which this could be done. To resolve this problem, the Agency has done considerable additional analysis to review Class III injection facilities from the perspectives

of current prevailing practice, existing regulatory requirements and potential environmental consequences. (See report of Geraghty and Miller.)

Our review looked at 9 Class III practices: Frasch sulfur mining; the solution mining of uranium, salt, and copper; in-situ combustion of oil shale, coal, lignite, and tar sands; and the extraction of geothermal energy. The similarities and differences of these nine groups of wells were compared with respect to a number of parameters. With regard to potential environmental impact, for example, 6 of the 9 practices inject into zones that may contain aquifers that would qualify as potential underground sources of drinking water under the UIC definition. In 8 of the 9 practices, injection normally occurs through overlying aquifers which would also meet the definition. With the exception of geothermal energy wells, injection pressures tend to be relatively high, and, with the exception of the Frasch process, the produced fluids could be considered hazardous in that they contain at least heavy metals. In 7 of the 9 cases, subsidence or catastrophic collapse is expected to accompany the operation.

The review of existing State controls and current practice also revealed more consistent similarities than consistent differences among these 9 types of practices. Based on this analysis, EPA has chosen not to establish requirements by subcategory of Class III.

The following changes have, however, been made in the requirements for Class III. With regard to construction requirements, the new casing and cementing standard to protect underground drinking water is applied only to new wells since a requirement for additional casing and cementing for an existing well with a life expectancy of a few months would make little sense. Existing injection wells used in the solution mining of salt and the recovery of geothermal energy, which tend to have a longer useful life, would, however, have to demonstrate mechanical integrity. The requirement for the use of corrosion resistant materials has been retained. However, it should be noted that this does not necessarily mean fiberglass, 316 stainless steel, or other exotic materials. It only means that the material used in the well must be adequate to meet the design life of the well. The performance history of the material under field conditions would be an adequate basis upon which to decide the appropriateness of construction materials. Logging and other testing requirements have already been discussed above. Deviation checks are required only in cases where construction involves a pilot hole with reaming. Other appropriate logging and testing is to be specified by the Director.

With regard to operating requirements, all new wells would have to demonstrate mechanical integrity before injection is begun. In the case of existing injection wells, only those with a longer useful life, such as the injection wells involved in the solution mining of salt and the production of geothermal energy would have to make an initial demonstration of mechanical integrity. Similarly, the periodic demonstration of mechanical integrity will apply only to the wells with longer life, i.e., salt and geothermal wells. The requirement for 5 monitoring wells has been removed, and monitoring requirements are now stated in terms of the objectives to be achieved. In the case of operations which inject into a formation which contains water with less than 10,000 mg/1 TDS, the requirement is that monitoring wells shall be completed into the injection zone and into any overlying USDWs. The monitoring wells shall be located in such a fashion as to detect any excursion of injection fluid outside the mining area. If the operation may be affected by subsidence, the monitoring wells shall be located so they will not be physically affected by the subsidence. In addition, in the case of injection wells which penetrate an underground source of drinking water in an area subject to subsidence, an appropriate number of monitoring wells is required to be completed into the underground source of drinking water to detect any migration of fluids. Again, the wells shall be located in such a fashion as to detect any migration and to be outside the physical influence of subsidence.

As noted above, the requirements have been clarified in a number of places to make them consistent with the use of area permits. For example, the information to be submitted to the Director specifies that this must be done only to the extent of establishing an adequate picture of the ore body and the subsurface geology in the mining site, but is not necessarily required in the case of each and every well.

The area of review requirement has been retained as proposed. This requirement, however, is not expected to place any undue burdens on the owner or operator. It is expected that the injector already has sufficient economic incentive to minimize the unintended leak of injection or produced fluids from the mining site. Furthermore, it should be noted that corrective action in the area of review is required only to preclude migration into drinking water sources. In cases for example, where the aquifers overlying the ore body have been designated to be exempted aquifers no corrective action may be required.

Finally, the final regulations have chosen to apply only limited aquifier restoration requirements on Class III as discussed earlier in this preamble.

D. Class IV. The coordination of RCRA and SDWA authorities in the regulation of Class I and Class IV wells used to inject hazardous wastes has been discussed earlier in this preamble. As stated there, the Agency has decided to require the operators of such wells to obtain interim status and to comply with the standards in 40 CFR Part 265 until the applicable State UIC program becomes effective.

In the final regulations, all wells which are used to inject "hazardous wastes," as defined under RCRA, are grouped into Classes I or IV. Standards for Class I wells have already been discussed above. Section 122.36 establishes, on an interim basis, a prohibition, also required for approvable State-administered programs, against the injection of hazardous waste directly into underground sources of drinking water. The prohibition is effective six months after the effective date of a State UIC program. Requirements applicable to other Class IV wells—those which inject above, but not into, USDW's—are reserved. Also reserved are additional requirements (for example, monitoring and retention of records) for Class IV wells injecting into USDW's.

Section 122.45 establishes additional requirements for operators of wells through which manifested hazardous wastes are injected. They apply to Class I wells and will apply to Class IV wells as final standards are established. This section essentially requires that the operator of such well comply with selected requirements established for hazardous waste management facilities under 40 CFR Part 122 Subpart C and 40 CFR Part 264.

The proposed standards for wells used to inject hazardous waste (122.45, 44 FR 34285, June 14, 1979) provided for a ban on the construction and operation of new Class IV wells, and a three-year phase-out of existing ones. The proposal would also have required that wells used to inject hazardous waste comply with the manifest and record-keeping requirements of the hazardous waste management regulations.

The final regulations reflect several changes from the proposal. *First*, the definition of Class IV has been narrowed. The proposal required only

that: (1) The well be owned or operated by a generator of hazardous waste, or the owner/operator of a hazardous waste management facility; and, (2) that the injection be into or above an USDW in order to be included in Class IV. Commenters correctly pointed out that this definition could embrace wells that were not in fact used to inject hazardous waste. This condition has now been added to the definition of Class IV. The definition also clarifies that the injection has to be "into or above a formation which, within one-quarter mile of the well, contains an USDW" (§ 122.32). Conversely, the injection of radioactive waste has been added. (See discussion above.)

The *second* major change from the proposal is that the requirements for Class IV wells, other than those injecting hazardous wastes into an USDW, are reserved. There are several reasons for this decision. While few commenters questioned the basic premise underlying the proposal, some questioned whether, at least in some cases, the migration of fluid into an USDW would in fact cause any adverse effects either on drinking water supplies or human health. Other commenters suggested that a well should not be banned if it overlies a deep or remote USDW which it is not likely to contaminate. As noted above, commenters also indicated their belief that the definition of Class IV was too broadly drawn, and that, therefore, the proposed standard was unnecessarily protective. The Agency has reviewed these comments and is mindful of its obligation to proceed with extraordinary care before imposing an absolute ban on any practice. The Agency's concern in fashioning the proposal was to afford protection to drinking water sources. The Agency is not contemplating any changes which would sacrifice or endanger drinking water sources people rely on. Furthermore, wells injecting hazardous wastes are also subject to RCRA which mandates a broader set of environmental concerns than drinking water. Nevertheless, there may well be portions of aquifers so deep or remote that they may never serve as drinking water sources, or conditions under which a particular injection may not have an impact on the quality of the drinking water source.

A further reason for the current approach is that regulation under RCRA and SDWA touch at several points. Facilities under Class I and Class IV overlap the class of facilities designated under RCRA as hazardous waste management facilities. It is, therefore, appropriate that technical standards under RCRA and UIC be consistent, to the extent allowable under the governing statutes, for facilities capable of causing a similar degree of environmental risk.

EPA has decided to defer issuance of permitting standards for HWM facilities until the Fall of 1980. Adoption of UIC standards now for Class IV wells could prove misleading to the States and the public because EPA might decide later this year to revise the standards to reflect policy decisions made in connection with RCRA standards. The best course is to defer the technical standards for Class IV wells which inject above USDWs until this Fall. Accordingly, we now solicit further comment on requirements for Class IV wells.

EPA has under consideration several options which would allow Class IV wells to inject, in certain circumstances. In order to assist commenters, these options are described below. After consideration of comments, EPA will publish regulations in the Fall of 1980 amending either 40 CFR Part 122, Subpart C, or 40 CFR Part 146, or both. At that time, EPA may decide to prohibit all Class IV wells as proposed, adopt any of the options discussed below, or adopt any combination or modification of the options which appears justified based upon the record, including comments received.

The definitions of an USDW and the term "endangerment" are discussed above in detail. For the proposed regulations, EPA adopted a conservative approach to the designation of USDWs. Within this regulatory approach, two alternative methods suggest themselves for expanding the range of allowable Class IV practices. The first is to attempt a more precise distinction between ground water in general and ground water that serves or can reasonably be expected to serve as a source of drinking water. Option A takes this approach.

A second possible approach is to attempt a more precise definition of the circumstances under which the presence of contaminants in an USDW may or may not cause a system to exceed national primary drinking water (NPDW) standards or otherwise adversely affect the health of persons. Option B takes the latter approach.

Option A. This option would entail modification of the definition of a USDW to decline to protect USDWs in areas adequately served by other sources. EPA is aware of areas of the country which are underlain by aquifers containing immense quantities of useable fresh water, or where surface water supplies are so plentiful that they could reasonably be expected to supply all foreseeable needs for drinking water. In such cases, EPA is willing to consider a policy which would authorize injection through Class IV wells.

In this approach, an additional basis for exemption could be added to § 146.04 that would allow the Director to decline to protect an aquifer or its portion if it "otherwise cannot reasonably be expected to serve as a source of drinking water." To justify such an exemption, the Director could be required to consider the following factors:

- Present and future availability of alternative sources of drinking water;
- Future population growth and land use patterns in the area; and
- The expected growth in the demand for drinking water.

In keeping with the revised definition noted above, such wells would fall under Class I because they would inject into exempted aquifers (i.e., not into, through or above an USDW). Injectors would apply for permits with a duration of up to ten years as specified in 40 CFR Part 146 Subpart B, with one exception. The applicant would be required to make a showing that the injection would not impact aquifers or portions of aquifers protected as USDWs. Such a showing would involve a demonstration that the injection zone is not in hydraulic connection with or that the natural flow from the injection zone is away from protected USDWs.

The application would be processed as any other Class I permit application. Under § 122.43, the Director would have the discretion to require such permit conditions as he believes necessary to protect USDWs.

Option B. This option would recognize that the injection or presence of contaminants in an USDW may not necessarily lead to drinking water supplies exceeding the NPDW standards or adverse effects on the health of persons. Based on this rationale, a more liberal approach could be taken to regulating Class IV wells if the applicant could demonstrate that the injection: (1) Is environmentally the most acceptable method of disposal; and (2) would not contaminate the portion of the aquifer from which water is drawn for drinking.

Under such an approach, the standard that the applicant would have to demonstrate would be that:

- Technology for safe disposal is not available, taking costs into account;
- Disposal by injection will be less harmful than use of other available means; and
- Technology and other means will be employed to reduce the volume and toxicity of wastes.

The applicant would be required to demonstrate that the proposed injection is the most environmentally acceptable alternative available considering technology and the cost of:

- Trucking to approved site;
- Pretreatment prior to injection;
- Treatment and surface discharge;
- Pretreatment and discharge into POTW;
- Construction of a Class I well;
- Incineration; and
- Segregation of streams and/or reduction in flow.

He would also have to demonstrate that anticipated ground water impact will not adversely affect the health of persons or violate NPDWs based on the following information:

- Injection volume and pressure;
- Life of operation;
- Depth of well;
- Direction of ground-water flow;
- Proximity to use;
- Monitoring up-gradient and down-gradient;
- Geological and hydrological data; and
- Closure plan.

There would be certain common elements under both options. Injectors would be required to obtain a permit to operate a Class IV well within one year of the effective date of the State program or close. Permits could be for a duration of 10 years, and new wells would be subject to the requirement in § 122.33 that a permit be obtained prior to the construction of a new well.

Similarly, there are certain common questions with regard to implementation under either option. The Agency solicits specific, detailed comments on these questions: *First,* do factual circumstances exist in which EPA should allow injection of hazardous waste into or above an underground source of drinking water? *Second,* if so, what information should be required of the applicant to show that the injection will not endanger drinking water sources, and what criteria should the Director use in granting or denying permits? *Third,* should new and existing Class IV wells be treated differently or alike? *Fourth,* should the decision to allow the use of a Class IV well be made as part of a statewide or regional plan (e.g., Sec. 208, land use, RCRA Sec. 4007 solid waste plan, UIC program application) or as part of the individual permit decision? *Fifth,* what factors should be considered in subdividing aquifers into relatively confined exempted areas and USDWs? *Sixth,* what procedures should be imposed to ensure full public participation in decisions to allow injection through Class IV wells? *Seventh,* what kinds of post-closure care requirements (monitoring, third-party liability, use restrictions) should be imposed on Class IV well operators? *Eighth,* are the authorities under SDWA and CWA sufficient to prevent the potential impacts of such injections or should RCRA authorities be invoked to meet environmental concerns such as aquifers discharging to streams and surface impacts on vegetation?

E. Class V. EPA received a number of comments with respect to Class V, suggesting that the two years allowed for the completion of an assessment and submission of State recommendations to EPA was insufficient. The Agency agrees with these comments. Consequently, these final regulations now allow the State three years instead of two years to complete the assessment of Class V wells and to submit recommendations for further regulation to EPA.

Amendments to Part 122

In the process of preparing the final Part 146 regulations, it became apparent that certain portions of the final consolidated permit regulations (45 FR 33290, May 19, 1980) would have to be amended to conform to the Agency's final decisions with regard to the UIC program. Four sections of Part 122 are amended as a part of this promulgation. This procedure is intended to avoid major inconsistencies between Parts 122 and 146. It is not intended to preclude further amendments that may be necessary, or to substitute for technical corrections (e.g., faulty cross references) of the consolidated permit regulations which the Agency still plans to make in the near future.

Section 122.18(c)(4)(ii). This paragraph in the final consolidated regulations required the Director to provide the Administrator with the necessary information to conduct a mid-course evaluation of the corrective action requirement as it applied to Class II wells. The Agency has decided to expand the mid-course evaluation in three ways: (1) It is to apply to Classes I and III as well as Class II; (2) it is to cover mechanical integrity in addition to corrective action; and (3) States are to provide the information every six months during the first two years of program operation rather than once at the end of two years. The amendment conforms the reporting requirement with this decision.

The Agency decided upon this course of action because we anticipate that an expanded mid-course evaluation will yield reliable information earlier than the promulgated scheme as a basis for any refinements in the UIC program requirements. This decision is discussed more fully as part of the evaluation plan described later in this preamble.

Section 122.37. This section detailed the requirements applicable to the authorization of injection wells by rule. It is revised to clear up some possible ambiguities with regard to the requirements applicable to certain types of rules. Specifically, paragraph (b) of the section may have raised questions with regard to the responsibilities of Class V injectors. Paragraphs (a) and (b) of the section have been revised extensively to clarify the Agency's intent. Paragraph (d)(1), relating to the contents of the injection well inventory is also amended. The current text inappropriately references § 146.52 which is a requirement for Class V. The revised text enumerates the information required on the national form for the inventory of injection wells (OMB #158–R0170), but does not change the substance of what is required.

Section 122.41(e). Paragraph 122.42(f) requires applicants for permits to submit a plan for plugging and abandonment, and specifies that the Director shall incorporate the approved plugging and abandonment requirements as conditions of the permit. The Agency chose this course of action because its concern for the proper abandonment of wells led it to establish such requirements as enforceable permit conditions. However, the permit terms for the UIC program may be long: up to ten years for Class I and up to the life of the well or facility for Classes II and III. Abandonment plans filed with the permit applications may easily be out of date by the time an injector is ready to close his well or facility. For the protection of both the injector and the environment, therefore, this requirement is amended by requiring the permittee to submit an updated abandment plan along with his 180-day notice. The Director is to review the updated plan, revise the relevant permit conditions as appropriate, and grant approval for the permittee to proceed with plugging and abandonment (see §§ 146.10, 146.14(c), 146.24(c) and 146.34(c)). Section 122.17(f) is amended to allow the permit to be modified to reflect this new plan as a minor modification.

Regulatory Analysis

The regulatory analysis consists of five basic sections: economic and financial profiles; alternatives considered; costs to industry and the States; impacts on the production of oil; and economic impacts on firms, regions and the economy. The cost section was entitled "Economic Impact" in the preamble to the proposed regulations. It

has been revised to show current estimates as well as to describe the reasons for change from the earlier analysis which appeared in the preamble. EPA's consultant did not include the cost associated with wells producing only gas because the percentage of injection wells associated with such wells is small in comparison with injection wells related to oil production.[1] Although the cost estimate is somewhat lower than would have resulted, had gas wells been included, EPA notes that other conventions which were adopted in the cost analysis tend to introduce possible overestimates in the overall cost of the program. To illustrate, as a result of the mid-course evaluation, changes might be made to the Regulations which would substantially reduce the cost to operators of determining the mechanical integrity of wells and performing remedial action.

Nevertheless the cost of the Regulations have been estimated as if there would be no relaxation of these requirements. In addition the Regulations allow, in 40 CFR 122.22(b)(3), the relevant authority to accept limited injection pressure in lieu of corrective action, if it can be demonstrated that the pressure of the injection zone does not exceed hydrostatic pressure at the site of any improperly completed or abandoned well within the area of review. Nevertheless, in estimating the cost of compliance, it was assumed, in all cases, that corrective action entailed physical repairs rather than pressure limitation. This assumption leads to an overestimate in the cost of the program.

Economic and Financial Profile

Overview. This section examines the impact of the regulations on operators of Class II and III wells. The relatively large number and dispersion of Class I, IV, and V wells among different industries precluded investigation of the economic impacts of regulation of these classes of wells.[2] However, the aggregate cost to operators and States have been included in the cost estimate.

On the whole, the impact of the Regulations on operators of Class II wells is expected to be relatively minor. It is estimated that a loss of crude production of about 13,000 barrels per day will result, which represents less than half of one percent of U.S. production at 1977 price and profit levels.[3] On a regional and producer level impacts will be more variable, depending upon the relative proportion of stripper wells, average stripper well production, company size and past construction practices. It is anticipated that operators in Illinois and the Mid-continent and Appalachian areas will be affected to a greater extent than other operators because these areas are characterized by poor completion practices and a large number of abandoned wells.[3a] Since production from stripper wells in these regions is relatively low, the net effect of the regulations may be the closure of those wells which produce very small amounts of oil but are likely to be the ones having potentially the greatest adverse impact on underground sources of drinking water.

Similarly the regulations will have no significant impact on Class III operators because compliance costs are relatively small, and the firms which engage in these practices are generally diversified and in sound financial condition.[4]

Oil and gas.[5] The oil and gas producing industry is comprised of a large number of firms but is dominated by a handful of vertically integrated corporations commonly known as the "majors". The majors engage in a full spectrum of activities including exploration, development, production, refining, transportation and marketing. The balance of firms in the industry, commonly known as "independents", are more diverse in structure. Although some independents engage in the same array of activities as the majors, they generally tend to focus on exploration, especially "wild catting".

Concentration in the petroleum industry is moderately high compared to other manufacturing industries. As indicated in table 1 the eight largest firms account for approximately half of industry revenues, which were $32.5 billion in 1977. Between 1973 and 1977 revenues have more than doubled. Net income, as a percent of net worth, was substantially higher in the five year period since the Arab oil embargo than the previous five year period. Despite the fluctuations in the net income/net worth ratio during the early part of the era ushered in by the embargo, it appears that the events of 1973 have reversed a general decline in this measure of profitability. Profitability appears to be increasing and the current increase in oil prices made possible by decontrol suggests that the trend will continue. (Table 2).

Table 1.—*Concentration, Oil and Gas Companies*

Firms	1973		1974		1975		1976		1977	
	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent
Largest 8	7.6	53	11.4	51	12.6	50	13.6	48	15.0	46
Next 9–32	3.8	26	6.0	27	6.8	27	7.5	26	8.7	27
All Other	3.0	21	4.9	22	6.0	23	7.3	26	8.8	27
Total	14.4	100	22.4	100	25.4	100	28.4	100	32.5	100

Source: Booz, Allen and Hamilton, Underground Injection Control Program . . ., P. II–12.

Table 2.—*Profitability of Petroleum Industry*

	Net income as a percent of net worth	
	Petroleum production and refining	Total trade
1967	12.8	13.2
1968	13.1	14.1
1969	11.9	13.5
1970	11.0	11.7
1971	11.2	11.7
1972	10.8	11.7
1973	15.6	12.7
1974	19.6	13.5
1975	13.9	13.0
1976	14.8	14.7
1977	14.0	15.0
1978	14.3	15.2

Source: Booz, Allen and Hamilton, *Underground Injection Control Program . . .*, p. II–14.

Frasch sulfur production. There are three major sources of domestically produced sulfur: (1) Recovered elemental, in which sulfur is produced as a by-product of natural gas processing and petroleum refining; (2) recovered sulfuric acid, in which sulfur is produced as a by-product of copper, lead, and zinc roasting and smelting; and (3) the Frasch process. Production by the Frasch process has declined between 1974 and 1977 while demand and prices have increased (Table 3). This decline is largely due to increases in the cost of heating water used to melt the sulfur, due to sharp increases in the price of natural gas. By the year 2000 it is possible that production by the Frasch

[1] Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program. Oil and Gas Well.* (June, 1979), p. 19.

[2] Booz, Allen and Hamilton, Inc., *Underground Injection Control Program. Industry Analysis of Class II and Class III Well Regulation.* (April 30, 1980) p. 1–2.

[3] *Ibid.*, p. III–4,5.

[3a] *Ibid.*, p. IV–3,4.

[4] *Ibid.*, p. III–14,18.

[5] For this discussion see *ibid.*, pp. II–8 to II–14.

process will be phased out, with expected increases in demand satisfied from present competing sources.[6]

The production of sulfur by the Frasch process is highly concentrated. In 1978 only five companies operating at ten sites produced sulfur by this method.[7] These companies have complete control over all phases of the production of sulfur. With one exception they are divisions of diversified companies whose sulfur sales represent, in most cases, a small portion of their total sales. These companies are financially secure, and their earnings outlook has improved owing to the growing demand for fertilizer, which they also produce and market.

Table 3.—*Sulfur Industry Data*

[Thousands of metric tons]

	1974	1975	1976	1977	1978
Domestic Production—					
Frasch	7,901	7,211	6,264	5,822	5,648
Recovered elemental	2,632	2,969	3,138	3,567	4,088
Other	886	1,079	1,305	1,169	1,439
Imports	2,150	1,897	1,727	1,977	2,177
Exports	2,663	1,352	1,270	1,178	[illegible]
Domestic Demand	10,906	11,804	11,164	11,357	12,486
Average Annual Price Per Metric Ton	[illegible]	$44.91	$45.72	$44.38	$45.17

Source: Booz, Allen and Hamilton, *Underground Injection Control Program . . .*, p. II–6.

Solution Mining of Salt.[8] About 60% of domestic salt production is by the injection process. Most of the solution mining wells are located on the Gulf Coast, primarily in Texas, Louisiana, and Mississippi. The major demand for salt is by the chemical industry, which uses about half of all salt produced in the U.S. for the production of chlorine and soda ash. Consequently, demand fluctuates with the demand by the chemical industry. About thirty companies produced salt by injection method in 1978. These companies generally employ other methods as well, namely, conventional mining and evaporation of brines.

In general companies producing salt are vertically and horizontally integrated. They tend to be involved in the production of chemicals, oil and gas, minerals, metals and pharmaceuticals. It appears that salt production is of relatively minor importance to these firms.

Solution Mining of Uranium. In 1978, there were ten firms mining uranium by the in-situ process. In general these firms are large conglomerates with holdings in other minerals, as well as oil and gas production. EPA could not obtain financial information on uranium mining firms because such information is not available. Furthermore, production information is confidential, which makes it impossible to ascertain mine or company output with any degree of precision.[9] Consequently, it is not possible to provide descriptive economic and financial information on the uranium mining industry in general, or the solution mining component, in particular.

Solution Mining of Potash.[10] Potash is used primarily in fertilizer as the source of potassium. Overall domestic demand for potash has been relatively stable since 1974, but domestic production has been falling as a proportion of total use. In 1965, domestic production represented 93% of demand, but in 1978, only 37%.

There are ten companies which produce potash, but only the Texas Gulf Company uses the solution mining technique. The remaining firms employ conventional mining or recovery from surface brines. As a proportion of total domestic production, the amount represented by the solution mining of potash is minor—1.25%.

Solution Mining of Copper.[11] The solution method is used to recover copper from low grade deposits. Presently, there are no commercial in-situ sites. Three marginally profitable solution sites and one experimental site were closed in 1978 due to depressed copper prices. Despite rapid price increases recently these sites have not been reopened.

In-Situ Oil Shale Combustion.[12] There are four projects in various stages of development, but none have progressed to full commercial use. Two of them—the Geokinetics, Inc. site in Utah, and the Equity Oil Co. site in the Piceance Creek Basin, Colorado—are still in the research and development stage. The others—the Rio Blanco Oil Shale Project, and Federal Lease Tract C both in the Piceance Creek Basin—are in the development stage, with burns scheduled for 1980. Even under favorable conditions the latter project, which is the most advanced of all the sites, is not expected to produce any sizeable amount of oil until 1986.

Gasification of Coal.[13] The Federal Government has sponsored research designed to demonstrate this technology since 1973, and three privately funded ventures have been organized since 1975. At this time none has progressed to commercial production. The most advanced sites are at the field test stage. The Department of Energy does not anticipate the commercialization of either of the sites it supports before 1987.

In-Situ Tar Sands Recovery.[14] Tar sands are heavy petroleum (bitumen) which will not flow into a well bore without stimulation. Ninety-eight percent of domestic resources are located in Utah. At this time, the technical feasibility of in-situ tar sands recovery is uncertain due to the lack of geologic and reservoir data.

Geothermal Energy.[15] The major use of geothermal energy is in the production of electricity. Such production, amounting to an installed capacity of 663 megawatts, is insignificant as a proportion of total U.S. production. Expansion of the use of this source of energy is hampered by high costs of development, long delays in obtaining permits and relatively high cost compared to generation by use of oil or gas. By 1985 this source may be price-competitive with oil and gas. However, at this time, only a small number of lease holders and owners of geothermal resources have undertaken its development.

Alternatives Considered

The Safe Drinking Water Act requires EPA to develop minimum requirements for effective state programs to protect underground sources of drinking water from the subsurface emplacement of fluids through well injection. The Act, however, also requires the Agency not to prescribe requirements which interfere with or impede the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or any underground injection for the secondary or tertiary recovery of oil or natural gas unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection.

In recognition of these requirements EPA considered numerous alternatives,

[6] *Ibid.*, p. II–20.
[7] *Ibid.*, p. II–21.
[8] For this discussion see *ibid.*, pp. II–26–29.
[9] *Ibid.*, p. II—26.
[10] Generally, *ibid.*, pp. II–29 to II–32.
[11] Generally, *ibid.*, pp. II–32 to II–36.
[12] Generally, *ibid.*, pp. II–36 to II–39.
[13] Generally, *ibid.*, pp. II–39 to II–41.
[14] Generally, *ibid.*, pp. II–41.
[15] Generally, *ibid.*, pp. II–42 to II–50.

spanning the range from no regulation at all to stringent levels of protection which would cost industry tens of billions of dollars. The following discussion will provide an understanding of the alternatives which received serious consideration but were eventually rejected.

Through an understanding of the nature of the alternatives and reasons for their rejection EPA hopes to instill an appreciation for the complexity of the problem it faced and for the balance it believes was achieved in the promulgated regulations.

I. Alternatives to Regulation

The promulgated regulations are based on the concept of prevention, which EPA believes reflects the intent of Congress in enacting the Safe Drinking Water Act. Through controls on the siting, construction, operation and abandonment of injection facilities, underground sources of drinking water will be protected from endangerment. An alternative to this concept is an approach which might be termed the "restitution" approach. It entails the creation of a fund, either through insurance premiums or other sources such as general tax revenues, which would be used to rectify any damage to an aquifer. The restitution alternative was not adopted for three reasons. First, it is inconsistent with the preventive nature of the Safe Drinking Water Act which requires EPA to promulgate regulations which contain minimum requirements for effective State programs to protect underground sources of drinking water. Second, the size of such a fund would have to be based upon an estimate of risk of contamination and the future value of the aquifer, both of which are unknown. And finally, even if such estimates were available there is no known technology by which a contaminated aquifer can be economically restored.

II. Alternative Regulatory Provisions

A. Class I.—1. *Treatment of nuclear wastes.* In the 1979 proposed regulations Class I was defined as "industrial and municipal disposal wells and nuclear storage and disposal wells that inject below all underground sources of drinking water".[16] The final regulations include nuclear storage and disposal wells which inject below underground sources of drinking water in Class V. EPA still considers such wells to require careful control. However, it believes that the control of such wells should be determined as part of the overall review of the disposal of nuclear wastes initiated under the President's Program of Radioactive Waste management, as described in the Message sent to Congress on February 12, 1980. Therefore, rather than prescribe specific construction requirements which may require modification in the near future, EPA concluded that it would be preferable to assess such wells and fashion appropriate regulatory requirements, in keeping with the President's program, in the future. (Wells which inject nuclear wastes directly into underground sources of drinking water are regulated under Class IV, however).

B. Class II.—1. *Casing cemented to the surface.* The regulations require that "* * * all new drilled Class II injection wells shall be cased and cemented to prevent migration of fluids into or between underground sources of drinking water" with the specific requirements left to the discretion of the State Director upon consideration of several factors as detailed in 146.22(b). An alternative considered would have required the cementing of surface casing from the injection zone completely to the surface as a way of ensuring that there would be no fluid migration along the exterior of the casing, or communication between water bearing strata. This alternative was not adopted because such a requirement, in EPA's view, far exceeds that which is necessary to prevent fluid movement. EPA believes that such a requirement would have interfered with or impeded the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or underground injection for the secondary or tertiary recovery of oil or natural gas without being essential to assure that underground sources of drinking water will not be endangered by such injection. To illustrate, if the Agency had required full cementing to protect underground sources of drinking water containing 3,000 ppm or less total dissolved solids, EPA estimates the cost to operators would have been roughly $20 billion over the first five years of the UIC program in 1977 prices.

2. *Interstate Oil Compact Commission (IOCC) proposal.* The promulgated Regulations do not differentiate between injection, producing and abandoned wells, based upon their age. The IOCC proposed that such a distinction be made as follows:

a. New wells and wells drilled or completed prior to 1947 would receive new permits based on mechanical integrity, area of review and remedial action;

b. Wells completed between 1962 and the time the State program goes into effect would continue under existing permits;

c. Permits for wells drilled or completed between 1947 and 1962 would be reviewed for compliance with standards prevailing since the early 1960's. Permits for wells that generally met the standards would be revalidated. Wells that clearly fall short of the standards would be re-permitted.

Many of the features of this proposal were adopted. New wells may not be constructed and operated without a permit; existing enhanced recovery wells may be operated under rule (although mechanical integrity tests are required to ensure that they remain sound); wells injecting in an existing field need only comply with standards for casing and cementing in existence at the time of drilling of such wells. Hence some of the major features of the IOCC proposal were adopted. It was not adopted in toto because under (b) it would have allowed wells completed between 1962 and the time the UIC program went into effect to be operated even if they were not mechanically sound. While EPA agrees that older wells may be more likely to fail owing to corrosion and other problems, it also believes that many newer wells may be subject to leakage and fluid migration due to the use of cement of insufficient quality, poor workmanship, a corrosive environment, human error, or other factors.

3. *Area of review alternatives.* Because of the high concentration of producing and abandoned wells in existing oil fields the overall cost to operators of the UIC program is largely determined by the extent of the area of review and nature of testing and remedial action required on wells within it. EPA devoted considerable effort to the identification and evaluation of alternative approaches. In its deliberations, EPA considered:

a. Applying it to all injection wells, both enhanced recovery and disposal, new and existing;

b. Applying it to new injection and existing disposal wells;

c. Requiring the radius to be a minimum of ½ mile of a new enhanced recovery or disposal well if the zone of endangering influence is not determined by the use of the Theis or similar equation;

d. An ad-hoc area of review, as practiced in Texas and Louisiana, and;

e. Eliminating the area of review requirement entirely.

Had alternative (a) been selected it would have required that virtually every injection, producing, and abandoned well of record in the United States be examined and, if necessary, either

[16] 44 FR 23740, April 20, 1979.

repaired, abandoned, or reabandoned within five years of the date the program became effective. Considering that there were about 1.2 million abandoned wells of record, 505,000 producing and 119,000 injection wells at the end of 1976, plus a net increase of some 25,000 new injection wells during the first five years of the program, EPA concluded that so comprehensive a requirement would have unduly impeded oil and gas production.

Option (b) was discarded for the same reason. Although fewer wells would have been reviewed within the first five years EPA believed that it would have unduly interfered with or impeded oil and gas production without being essential to assure that underground sources of drinking water will not be endangered. Similiarly alternative (c) was rejected for the same reason. Had the one half mile radius for the area of review been adopted, 171,000 producing wells and 302,000 abandoned wells would have been evaluated, and 20,000 repaired. At the one fourth mile radius there is a reduction of some 77,000 producing and abandoned wells in the area of review. At the smaller radius, the number of producing and abandoned wells needing remedial action is approximately 17,000 compared to about 20,000 at the ½ mile radius.

The ad-hoc alternative (d) would require the testing and appropriate remedial action to wells in the area of review of a new diposal well only if the regulatory authority received a complaint within the ten days of the filing of a permit application. While its low cost makes it appealing, this option was rejected because it would have provided for remedial action to faulty wells only after environmental damage had become visible.

Alternative (e) was rejected because even though the injection well was sound, other nearby wells could still serve as pathways for potential endangerment.

Radii less than ¼ mile were not considered because actual computations by EPA of the zone of endangering influence indicate that, in most instances, the appropriate distance is less than ¼ mile. Setting the radius at ¼ mile thereby ensures that all wells within the zone of endangering influence will be examined.

4. *Other alternatives to reduce or spread out program costs.* a. Sampling a small portion of wells for mechanical integrity. Testing and reporting the results of mechanical integrity tests on injection wells accounts for approximately $96 million of total program costs. EPA considered random sampling as an alternative to testing of all wells. This approach was not adopted because data essential to the design of the sample, e.g., the different sampling strata to sample and expected failure rates, are not available. A random sample would provide an estimate of failure rates but would fail to locate all defective wells. [16a]

b. *Assessment/Postponement.* This option would postpone the date by which permits are required by about three years while the States planned and conducted an assessment of injection practices. The data base resulting from this approach would then be used to formulate a regulatory program. This alternative was rejected for two reasons. First, the assessment would have required an expensive survey in each state and would not provide a valid test of the area-of-review concept. Second, the program would have been delayed three years, which was judged by EPA to be unacceptable.

c. *Exempting stripper-related injection wells.* Approximately three-quarters of all producing wells are strippers, which are wells producing ten or fewer barrels of oil per day. It appeared that exempting from regulation injection wells associated with strippers would achieve the dual objective of reducing program costs substantially while sparing the least productive wells the burden of the cost of compliance. Unfortunately, the very reason that enables the savings in program costs also weighs against the adoption of this alternative. To exclude three-quarters of all producing wells from any kind of review would undermine the effectiveness of the program for two reasons. First, strippers number among them some of the oldest wells drilled in the U.S. Old stripper wells are not drilled to current standards and are the ones most likely to endanger underground sources of drinking water. Second, because of their numbers and widespread distribution entire regions of the country will be left unprotected if injection wells associated with strippers are exempted.

d. *Exempting injection wells with an open annulus from pressure testing.* The promulgated regulations require pressure testing of all injection wells for casing leaks. Where the annulus is enclosed, the cost of such a test is estimated to be thirty dollars.[17] However, if a well does not have an enclosed annulus the cost of testing is estimated to be $1500.[17] Over the first five years of the program the cost of testing wells with an open annulus is estimated to be $65 million, and affects about 43,000 wells. EPA considered eliminating the testing requirement, but decided to retain it because of the large number of such wells and their potential for widespread contamination.

5. *Other, more stringent alternatives.* As discussed under (1) and (3) above, more stringent alternatives rejected were: Continuous cementing from the injection zone to the surface; area of review for all injection wells, and a half-mile, rather than quarter mile, area of review. Following are three additional alternatives which were considered by EPA. Each would have imposed more stringent requirements than those promulgated:

a. *Continuous monitoring of injection pressure, volume and flow rate.* Unlike the continuous monitoring required for Class I and III wells, such monitoring was considered but rejected for Class II because the injected fluid, being less toxic and corrosive than that of Class I and III wells, does not require constant surveillance. In addition, the Agency believes that the cost of continuous monitoring would have been excessive in view of the potential for harm to human health.

b. *Absolute construction ban without a permit.* In the case of a non-controversial application EPA estimates that the process will require about 105 days over and above current State permit processing times. For wildcat operations EPA believes that such a delay would be particularly expensive and would have unduly interfered with or impeded oil and gas production. Consequently, the promulgated regulations allowed the issuance of temporary emergency permits if it can be demonstrated that "a substantial delay in production of oil or gas resources will occur unless temporary emergency permit is granted to a new Class II well and the temporary authorization will not result in the movement of fluids into an underground source of drinking water." [18]

c. *Extending coverage to wells storing hydrocarbons in a gaseous state.* The April, 1979 proposed regulations included all forms of hydrocarbon storage under the definition of Class II.[19] Wells storing hydrocarbons which are a gas at standard temperature and pressure have been excluded from Class II in the promulgated regulations

[16a] Booz, Allen and Hamilton, *A Study of Sampling Procedures as Applied to the Mechanical Integrity Testing of Injection Wells.* (April 30, 1980). Executive Summary, pp. 1,2.

[17] Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program, Oil and Gas Wells.* (June, 1979), p. 96.

[18] 40 CFR 122.40(a)(3).

[19] 44 FR 23758, April 20, 1979 and 44 FR 122.34(b), June 14, 1979.

because gas is highly unlikely to result in the chemical contamination of drinking water even if it migrates from the injection zone. In addition such wells may be properly maintained owing to strong economic incentives to prevent loss of the stored gas. These wells have been transferred to Class V for further study.

C. In response to comments that Class III wells were too diverse to be covered by common requirements, EPA undertook a detailed evaluation of their physical characteristics and potential for contamination of underground sources of drinking water in order to determine if subclassification of Class III wells was appropriate.[20]

The review looked at 9 Class III practices: Frasch sulfur mining; the solution mining of uranium, salt, and copper; in-situ combustion of oil shale, coal, lignite, and tar sands; and the extraction of geothermal energy. The similarities and differences of these nine groups of wells were compared with respect to a number of parameters.[21] With regard to potential environmental impact, for example, 6 of the 9 practices inject in zones that may contain aquifiers that would qualify as potential underground sources of drinking water under the UIC definition. In 8 of the 9 practices, injection normally occurs through overlying aquifiers which would also meet the definition. With the exception of geothermal energy wells, injection pressures tend to be relatively high, and, with the exception of the Frasch process, the produced fluids could be considered hazardous in that they contain at least heavy metals. In 7 of the 9 cases, subsidence or catastrophic collapse is expected to accompany the operation.

The review of existing State controls and current practice also revealed more consistent similarities than consistent differences among these 9 types of practices. In addition, the theoretically preferable criterion cannot be translated into operational terms. According to EPA's consultant, "perhaps the most logical way to subclassify the Class III wells, would be in terms of the relative threats to the ground-water environment posed by different practices." [22] However the Agency's consultant also concluded that the " * * * overall threat to the ground-water environment that might be posed by a particular type of injection well in Class III depends to a large degree on the site-specific hydrogeologic situation." [23] The agency cannot develop consistent National Standards based upon diverse, local, hydrogeologic factors. Therefore, EPA has chosen not to subclassify Class III. However, in recognition of the relatively short service life of wells other than salt solution and geothermal,[24] EPA concluded that the mechanical integrity testing requirements for certain existing wells in Class III should be relaxed.

Consequently, prior to granting approval for the operation of a Class III well, the operator is required to demonstrate mechanical integrity only for all new Class III wells and existing salt and geothermal wells. In addition, only the operators of salt solution mining and geothermal wells are required to demonstrate mechanical integrity every five years.[25]

Two, more stringent alternatives were considered for the abandonment of Class III wells, notably those relating to uranium mining: Aquifer restoration, and containment of injected fluids. The restoration alternative was not adopted because the technology is still in the experimental stage. Since EPA cannot evaluate the effectiveness of this technology it concluded that it was premature to require it now as a National minimum requirement. However the Director is given the discretion to require aquifer restoration on a case-by-case basis.[26] As for the containment alternative, the Agency concluded that because of the long decay time of radioactive substances, containment would require monitoring and testing of water quality for hundreds of years, which the Agency does not believe to be administratively feasible at this time.

D. Classes IV and V. Four alternative approaches were formulated for regulation of wells which inject directly into or above underground sources of drinking water: [27]

1. Within the UIC regulations, require a permit program for at least some of these practices;

2. Within the UIC regulations, require the states to assess the threat of contamination from these wells and submit a detailed state plan to EPA;

3. Withdraw consideration of these wells from the UIC regulations and study them in a separate national assessment; and

4. Within the UIC regulations, require state assessment of these wells coupled with regulatory control over the most potentially harmful practices. The main features of alternative number 1 are:

- The Director would have the discretion to ban immediately those categories of practices which present an unreasonable risk to health and to ban, after an appropriate period of time, all categories of practices for which economically feasible alternatives exist;
- The Director would determine, for those practices not banned, which practices in the state should be regulated by permit rather than by rule;
- Exemptions would be allowed based upon criteria such as toxicity and/or volume, hydrogeologic characteristics, and population in the area relying on the affected underground sources of drinking water;
- The Director would impose monitoring, record-keeping and reporting requirements for each permit. In addition, the director would require public notification for each permit before its issuance, and require that the injector periodically show that the well continues to be the best environmental means of disposing of the waste.

This approach would have provided maximum protection of underground drinking water souces within the shortest time frame, and would have been consistent with other Subparts of the UIC regulations. It was not adopted because a substantial effort would have been required to locate individual wells that are typically hidden from view. In addition, it is impossible to argue with certainty that technological alternatives to current practices are economically feasible for all shallow disposal and recharge well practices. Considering the absence of a complete characterization of wells, it is possible that some permit requirements would be established without a thorough understanding of all elements of operations such as volume and toxicity, of injected fluids, costs and alternatives.

The main features of alternative number 2 are:

- The Director would compile an inventory, including number, location, and use of these wells and determine the toxicity and volume of the injected fluids;
- The Director would develop and compile hydrogeologic data such as location of the aquifers, aquifer yield, ground-water quality, ground-water movement and ground-water use;
- The Director would develop data on present and future population and industrialization, emphasizing the dependence upon ground-water and the protection of public health;

[20] Geraghty and Miller, Inc., *Development of Procedures for Subclassification of Class III Injection Wells.* (April 30, 1980).

[21] *Ibid.*, p. 8.

[22] *Ibid.*, p. VI.

[23] *Ibid.*, p. VII.

[24] *Ibid.*, p. 8.

[25] 40 CFR 146.34(b)(2) and 40 CFR 146.33(b)(3).

[26] 40 CFR 146.10(d).

[27] For a full discussion of these alternatives, see Temple, Barker and Sloane, Inc., *Analysis of Cost. Underground Injection Control Regulations. Class I and Class III Wells. Class IV and Class V Wells.* (May, 1979), Part 2, Appendix B.

• The Director would consider the technological alternatives available to existing practices; and

• The Director would assess the risk to underground sources of drinking water and would submit a State plan to cover new and existing injection wells.

The advantages of this alternative are, the study would be mandatory, being required by regulation; provision could be made for the Director to take action in the event cases of endangerment are uncovered during the course of the study and there would be a greater degree of uniformity in several important aspects of the study, such as scope; methodology; and data quality. The major disadvantages to this approach, which led to its rejection by the Agency, is that it is time consuming and would allow extremely dangerous practices to continue on a widespread basis while the problem was studied further.

The third alternative is similar to the second, except that the study would be voluntary. The same type of information would be collected; however, the alternative would suffer from the same disadvantages as the former alternative. In addition, the Director might not have the authority to ban dangerous practices which are uncovered. Consequently, the Agency rejected this approach as well.

The fourth alternative was selected by EPA. It combines regulation of the most dangerous practices (Class IV) with further study of those believed to be of less immediate concern (generally, those wells in Class V). Under alternative number four, the injection of hazardous wastes directly into an underground source of drinking water after six months following approval or promulgation of any UIC program for a State, is prohibited. The control of injection of hazardous wastes above USDWs is reserved until the Fall.

Cost of Compliance

Most States already regulate the underground injection of fluids in some manner or to some degree. State personnel are already assigned to work on the control of injection wells, and owners and operators of injection wells must meet existing State requirements. Nevertheless, the UIC regulations will cause both States and industry to commit resources to the protection of underground sources of drinking water in addition to their current level of effort.

EPA's best estimate is that these regulations will result in incremental costs of approximately $775 million, expressed in 1977 prices, to all 57 States and Territories and the regulated community in the first five years of program operation (Table 4 provides a summary). This estimate includes costs only for developing and conducting the assessment of Class V wells and does not try to guess the impact of immediate closures or the eventual regulatory requirements. In addition, no attempt was made to anticipate the changed requirements that may result from the mid-course evaluation of the area of review requirement, or from the review of a sample of wells which were permitted on the basis of cementing records. This is because EPA does not have a sufficient basis for projecting the number of wells which will require remedial action.

Table 4.—*Summary of Five-Year Incremental Costs of UIC Regulation*

[In thousands of 1977 dollars]

	Non-recurring	Recurring	Total
Industry:			
Class I	5,025	463	5,488
Class II	565,094	4,005	569,100
Class III	5,698	560	6,258
Class IV	1,100	162,300	163,400
Subtotal	576,917	167,329	744,246
State:			
Class I	875	2,535	3,410
Class II	9,855	7,560	17,415
Class III	709	1,230	1,939
Class IV	389	858	1,247
Class V	7,200		7,200
Subtotal	19,028	12,183	31,211
Total	595,945	179,512	775,457

In this study price levels which existed in 1977 were used to estimate the cost of the UIC program. The use of "constant" prices is a commonly used convention which enables one to ascertain the physical amount of goods and services, or "real" resources, devoted to compliance because it eliminates the influence of changes in prices. For other types of analysis, such as projecting expenditures and revenues in a given year, it would be appropriate to use prices expected to prevail during the time period of interest. If it is desired to express the cost estimates in terms of "current" prices it would be necessary either to project the level of each unit price, or to construct a price index which would be used to convert the aggregate cost estimates from 1977 to other price levels. Such an endeavor is beyond the scope of this analysis. However, in the judgment of EPA's consultant, increases in costs suggest that the annual rate of price level increase for activities associated with oil drilling and production is roughly on the order of 20% per year.[28]

Consequently a rough estimate of the cost of the UIC program in general, and Class II in particular, in 1980 prices, may be obtained by adjusting costs upward by 50%. The total cost of the Regulations in 1980 prices would be on the order of $1.2 billion, or about $230 million per year.

It should be emphasized that the estimate is largely a function of the size of the environmental problem. The cost to industry, in 1977 prices, of carrying out the fixed requirements—permit application, permit issuance, inspection, surveillance, monitoring, testing, reporting, etc.[29]—is estimated to be $191 million, or $38 million annually for the first five years. This is, in a sense, the fixed cost of the regulations. The remainder, $553 million, is the estimated cost, in the first five years, of repairing leaky injection wells, replugging wells improperly abandoned in the first place, and re-cementing improperly completed producing wells in the area of review. For Class IV, these costs include the pretreatment of hazardous waste and shipment to approved hazardous waste management facilities. These are the variable costs which directly depend upon the number of problem wells. If the environmental problem is more or less extensive than estimated by EPA in this analysis, this portion of the cost would vary accordingly and potentially widely.

Of the total $775 million estimated cost, about $744 million falls on industry. The total incremental State burden is estimated to be about $31 million over five years or about $6 million annually.

The cost of regulating Class II injection wells, $569 million to industry over five years, clearly dominates both State and industry costs. However, this class also has the largest number of wells (2 million) potentially affected by the regulations.

The following discussion provides details of the cost estimates by class of well. The sections are organized into industry estimates and State estimates. They also discuss nonrecurring and recurring costs. Nonrecurring costs include such one-time activities as inventorying wells in the area of review, taking appropriate remedial action, and repermitting existing wells. Demonstrations of mechanical integrity are also treated as one-time costs because the second round of tests will not take place in the first five year

[28] *In Geraghty and Miller, Inc., Development of Procedures and Costs for Proper Abandonment and Plugging of Injection Wells* (April 30, 1980), p. IV–5, the cost of abandoning a 3,000 foot well used either for oil and gas storage or production is $8,600. In order to estimate the cost of abandonment in 1977 prices, EPA's consultant, Booz, Allen and Hamilton, reduced this to $5,000, which indicates a growth rate of approximately 20% per year (*Underground Injection Control Program Class II Well Incremental Compliance Cost Refinements*, p. 16).

[29] 40 CFR 122.45.

period. Recurring costs include such periodically required activities as monitoring, reporting, and enforcement.

Class I Wells. 1. *Industry Costs.* A demonstration of mechanical integrity will be required of operators but flexibility is provided in the choice of test for demonstrating it. Unit costs can range from $5,000 to $35,000 [30] per test. The total cost of mechanical integrity testing for the UIC program is estimated to be in the range of $675,000 to $4.5 million.[31]

Appropriate remedial work is prescribed for defective wells and may vary from $17,500 to $100,000.[32] Total incremental repair costs for the class are estimated to range from $53,000 to $300,000.[33]

The average number of new wells being constructed each year is estimated at twenty.[34] Since all States now have permitting requirements at least as stringent as the UIC requirements, new construction will incorporate the new design criteria contained in these regulations and no incremental construction costs are expected to result.[35]

Additional reporting requirements have been estimated to cost $300 per well per year for new and existing deep disposal wells.[36] Total recurring costs are estimated to be $463,000 over five years.[37]

2. *State Costs.* The regulations require collection and review of data on a quarterly basis for each site subject to the regulations. Six work-hours per submission per site has been employed in the estimation of costs for this activity.[38] EPA estimates that the submission of reports to the Agency will require one hour of preparation per site per quarter.

The total costs of the requirements in Class I appear in Table 5. The increase in industry and state costs since the proposed regulations is due to a revision in the number of existing wells, based upon a new survey of the well population.[39]

Class II Wells. Class II wells include injection wells associated with oil and gas production, and hydrocarbon storage, except gaseous natural gas storage wells. The conceptual scheme for estimating incremental costs involves the identification of unit costs for the activities required by the proposed regulations and multiplying those by the estimated number of wells requiring each kind of action. Several changes have been made to the cost of compliance based upon comments received and further analysis performed by EPA. On net balance cost to operators is lower than the previous estimate, primarily due to lower costs of remedial action. This results from the recognition that certain wells will be abandoned rather than reparied. A reconciliation of changes in costs from those appearing in the April 20, 1979, Preamble follows:

Table 5.—*Incremental Five Year Program Costs, Class I Wells*

(In thousands of 1977 dollars)

	Nonrecurring	Recurring	Total
Industry:			
Mechanical Integrity Test	675–4, 725		675–4,725
Remedial Action	50–300		50–300
Monitoring and Reporting		463	
Subtotal	728–5,025	463	1,191–5,488
State:			
Program Development	52–127		52–127
Program Hearings	39		39
Permit Existing Wells	298–593		298–593
Permit Hearings	116		116
Quarterly Review		545	545
Quarterly Report		130	130
Annual Report		50–245	50–245
Enforcement		830–1,615	830–1,615
Subtotal	505–875	1,555–2,535	2,060–3,410
Total	1,233–5,900	2,018–2,998	3,251–8,898

Source: Temple, Barker and Sloane, Inc., *Underground Injection Control Regulations. Analysis of State Program Costs: Class I Wells.* (May 15, 1980) p. 6.

1. *Sampling for fluid migration (+$4.5 million).* The proposed regulations permitted the submission of cementing records as a demonstration of mechanical integrity. However, EPA's contractor advised the Agency that "existing well records have limited use in determining the adequacy of the cement sheath outside of a well casing".[40] For certain existing Class II wells, the absence of fluid migration will be based on well records. A sample of these wells will be tested in order to ascertain if reliance upon well records was adequate as an indicator of the mechanical integrity of the well. The costs of this requirement are based upon a sample of 3,000 injection wells nationwide.

2. *Initial reporting of test results—existing enhanced recovery wells (+$2.5 million).* In the case of new injection wells and existing disposal wells test results are reported in the permit application. However, existing enhanced recovery injection wells may be covered by rule, but no provision was made for reporting test results to the State Director. This omission has been corrected by attributing to operators of wells covered by rule, a cost of $25 per report.

3. *Financial responsibility (+$5.0 million).* The April 1979 reproposal did not include the cost, to operators of existing enhanced recovery wells, of securing a well closure bond. Costs for such wells were estimated in the same fashion as costs for existing disposal well operators.

4. *Unit permitting cost (+$2.2 million).* In EPA's earlier analysis the unit cost of permit application used in table XIV–1 [41] to calculate the five-year cost to industry was inconsistent with the unit cost which should have been used, as calculated in Chapter XI.[42] Previously the cost for permitting new salt water disposal (SWD), new enhanced recovery and existing SWD wells was $620; $367 and $240, respectively. The correct unit costs are $675; $422 and $262, respectively.

5. *Changes accruing to well closure and injection wells not put in service ($−92.8 million).* In EPA's earlier estimate it was assumed that wells would either be repaired, or abandoned and redrilled, depending on the type of well. In the current analysis the results of the production impact analysis have been integrated into the cost analysis.[43] The cost model now recognizes that the predicted number of new enhanced recovery (ER) wells will be reduced by 2,470 as a result of the evaluation of the area of review. It is estimated that the

[30] Temple, Barker and Sloane, *op.cit.*, Part I, p. II–10.

[31] Geraghty and Miller, Inc., *Economic Analysis, Class I Rehabilitation.* (April 30, 1980).

[32] Temple, Barker and Sloane, *op.cit.*, Part I, p. II–11.

[33] Geraghty and Miller, *op.cit.*, Part I, p. II–5.

[34] Temple, Barker, and Sloane, *op.cit.*, Part I, p. II–5.

[35] Ibid., Part I, p. II–12.

[36] Ibid., Part I, p. II–12.

[37] Geraghty and Miller, *op.cit.*, p. 14.

[38] Temple, Barker and Sloane, *op. cit.*, Part I, p. III–6.

[39] Geraghty and Miller, *op. cit.*, p. 9.

[40] Geraghty and Miller, Inc., *Mechanical Integrity Testing of Injection Wells.* (April 30, 1980), p. 9.

[41] Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program. Oil and Gas Wells. (June, 1979), p. 196.*

[42] *Ibid.*, p. 159.

[43] Booz, Allen and Hamilton, *op. cit.*, pp. 16 ff.

evaluation will show (1) a producing well needing remedial action; (2) an abandoned well requiring reabandonment; or (3) both (1) and (2). It is judged that the anticipated production will not warrant the required expenditures to repair an estimated 2,220 abandoned wells and 88 producing wells. The operator will therefore choose not to place the new ER wells in service, thereby avoiding the cost of remedial action to wells in the area of review. Savings, relative to EPA's earlier costs estimate, amount to $70.8 million. Similarly, forty new (i.e., converted) ER wells will require remedial action but will be abandoned rather than repaired. This reduces EPA's earlier cost estimated by $1.0 million.

EPA estimates that fifteen new salt water disposal wells will not be placed in service due to the need to repair both a producing and abandoned well in the area of review. Fifteen abandoned wells and a like number of producing wells will not be repaired, resulting in a reduction of $750 thousand from EPA's earlier estimate.

In addition, (a) 590 existing ER and 500 existing SWD wells will be abandoned rather than repaired. When the cost of abandoning the injection and associated producing wells is taken into account, the "savings" over EPA's earlier cost estimate is estimated to be $18.9 million; and (b) seventy five existing SWD wells will be abandoned rather than repaired, at a net "savings" of $150,000.

Finally, the abandonment of wells and decision not to put new injection wells into service results in savings in the cost of permitting, reporting the results of mechanical integrity tests and obtaining plugging bonds. These "indirect" savings total $1.2 million.

Table 6 shows a reconciliation of the earlier Class II cost estimate and the current one. In all cases where a well was abandoned rather than repaired, the cost of its abandonment was properly considered in the calculation of the "savings" over EPA's prior cost estimate.

1. *Industry Costs.*—Incremental non-recurring costs of compliance to operators are estimated to be $565 million over the first five year period. Of this total $20 million are for the preparation of permit applications, and $149 million are the cost associated with determining the nature and extent of corrective action. The bulk of these costs, $396 million, is the estimated cost of the corrective work itself.

Table 6.—*Reconciliation of Current and Previous Class II Industry Costs*

[Thousands of 1977 dollars]

1. April, 1979 estimate [1]	$647,000
2. Alaska	+700
3. Initial reporting of test results for existing ER wells	+2,500
4. Plugging bond, existing ER wells	+5,000
5. Correction, unit cost of permitting	+2,200
6. Random sampling for fluid migration	+4,500
7. Production impact analysis	−192,800
8. Current cost estimate	569,000

[1] Arthur D. Little, Inc., Cost of Compliance. Proposal Underground *Injection Control Program. Oil and Gas Wells.* (June, 1979) pp. 196–200. Includes recurring costs.

Source: Booz, Allen and Hamilton, Inc., *Underground Injection Control Program Class II Well Incremental Compliance Cost Refinements.* (April 30, 1980), p. 33.

In estimating the cost of corrective action the unit cost of reabandoning a well was taken as $20,000. EPA reviewed the validity of this estimate since the proposal by surveying costs of reabandonment experienced by operators and state regulatory agencies between 1975 and 1979 in Louisiana, Michigan and Texas. After adjusting for changes in price levels EPA's consultant concluded that $20,000 represented a reasonable average of the considerable range of unit costs uncovered by the survey.[44]

On the average, industry will experience one-time costs of some $113 million per year over a five-year period. These estimates assume the current requirements for Class II and do not try to anticipate the outcome of the mid-course evaluation regarding the area of review requirement.

In addition to the one-time costs associated with existing wells, there are incremental costs which producers will incur each year to collect and report monitoring data. The total recurring costs attributable to the regulation are estimated at $4 million over five years or about $800,000 per year. (Table 7).

A note of caution is warranted regarding the correct interpretation of the costs to Class II operators. First, it was assumed in the estimating methodology that the area of review would be ¼ mile in all cases. EPA believes that this assumption results in an overstatement of industry costs because the area of review, when calculated by a mathematical formula as permitted by the regulations, will probably be substantially less than ¼ mile in most cases. This means that the number of producing and abandoned wells subject to testing, correction and reporting requirements is substantially less than the number ascertained through the use of the ¼ mile assumption.

[44] Booz, Allen and Hamilton, *op. cit.*, p. 11.

Table 7.—*Incremental Five-Year Costs to Producers, Class II Wells*

[Thousands of 1977 dollars]

NON-RECURRING:	
Evaluation of Construction:	
Previously Abandoned Wells	12,600
Producing Wells	28,200
Injection Wells*	108,500
Subtotal	149,300
Corrective Action:	
Previously Abandoned Wells	258,100
Producing Wells	38,500
Injection Wells	85,400
Abandon injection wells and associated producing wells	13,800
Subtotal	395,800
Permit Application	20,100
Subtotal, non-recurring	565,200
RECURRING:	
Monitoring and Reporting	4,000
Total	569,000

*Includes plugging bond for existing enhanced recovery wells.

Note.—Does not add to total due to rounding.

2. *State Costs.*—The estimate of the incremental costs to States, of implementing the proposed UIC control program for Class II, is based on an estimate of the total effort that will be required in oil-producing States to enforce the proposed Federal regulations. The amount currently spent on UIC programs by these States was then subtracted from the total, yielding the incremental costs.[45]

It is estimated that oil-producing states will incur total costs of $38 million over a five year period. Of this, $16 million will be one-time costs to re-permit existing disposal wells and other start-up costs. The remaining $22 million will cover the permitting of new wells, monitoring and enforcement, and general overhead. Since current State spending projected for five years equals $20.7 million, incremental costs over five years are $17 million or $3.5 million annually (Table 8).

Class III Wells. Special process mining is, in most instances, a developing technology already operating under some State controls. There are about 8,000 wells but a relatively small number of sites at the present time.[46] Consequently, the costs of compliance are estimated to be small and the impact on the industry to be negligible.

Table 8.—*Incremental Five-Year Costs to States, Class II Wells*

[Thousands of 1977 dollars]

Non-recurring:	
Ground Water Inventory	2,174
Permit Existing Disposal Wells	7,810
Permit New Wells	4,505
Other	2,072
Subtotal	16,560

[45] Arthur D. Little, Inc., *op. cit.*, p. 183.

[46] Geraghty and Miller, *op. cit.*, p. 4.

Table 8.—*Incremental Five-Year Costs to States, Class II Wells* —Continued

[Thousands of 1977 dollars]

Recurring:	
Overhead	5,590
Enforcement	13,802
Monitoring Reports	2,203
Subtotal	21,595
Total State Cost	38,155
Less: Current State Spending	−20,740
Total Incremental State Cost	17,415
Recurring	7,650
Non-recurring	9,855

Source: Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program. Oil and Gas Wells.* (June, 1979), p. 193, and U.S. Environmental Protection Agency, *Class II State Cost* (May, 1980).

1. *Industry Costs.*—The total incremental cost to industry of complying with Class III requirements is estimated to be $6.3 million for the first five years, or about $1.3 million annually. Of this, about $5.7 million are nonrecurring costs mainly associated with the test for mechanical integrity and repair of faulty wells. The remaining half-million dollars are the cost of monitoring and reporting.[47]

The States of Texas and Louisiana account for all current Frasch process sulfur mining. There are ten mine fields with approximately 500 wells in the two States. The average useful life of a Frasch well is about one year. Since this practice was started eighty years ago, approximately 35,000 wells have been drilled.[48]

The total one-time permitting expenses for the ten fields will be approximately $34,000, and reporting costs, $15,000 over five years.

There are eighty operating salt solution mining sites in the United States, principally in Texas, Louisiana, Michigan, New York, Ohio, and Kansas, containing approximately one thousand wells. Permit applications expenses for the thirty fields are estimated to total $204,000 and incremental annual reporting requirement expenses are estimated at $165,000 over five years. The total one-time cost of mechanical integrity testing is estimated to be one-half million dollars.

One operating field with 18 wells (17 injection and one extraction) for the solution mining of potash exists in Moab, Utah.[49] Permit application requirements for the site will involve a one-time cost of $30,000.[50] There will be no costs for integrity testing of the injection wells, as all abandoned wells in the field are thought to be adequately plugged.[51] Therefore no cost will be incurred by the operator for reviewing nearby wells. There will be recurring incremental costs of $100,000 for reporting over a five year period.

Summaries of the one-time costs and annual recurring costs to industry are presented in Table 9.

2. *State Costs.*—The regulations require collection and review of data on a quarterly basis for each site subject to the regulations. Seven hours per submission per site has been employed in estimating state costs. The submission of an annual report to EPA will require 3 to 35 work days per State to comply with the regulations, depending on the number of permits issued, quarterly reports reviewed, and other regulatory activities.

Table 9.—*Incremental Five-Year Costs to Industry, Class III*

[In thousands of 1977 dollars]

	Permitting	Mechanical integrity test	Monitoring wells	Remedial action	Total
Non-recurring:					
In-situ gasification	10	0	0	0	10
Uranium leaching	60	0	0	0	60
Geothermal	10	0	0	0	10
In-situ copper leaching	31	0	300	0	331
Frasch sulfur mining	34	0	0	0	34
Solution mining of salt	204	519	3,000	1,500	5,223
Solution mining of potash	30	0	0	0	30
Subtotal	379	519	3,300	1,500	5,698

	Monitoring	Reporting	Total
Recurring:			
In-situ gasification	0	11	11
Uranium leaching	0	53	53
Geothermal	0	9	9
In-situ copper leaching	18	9	27
Frasch sulfur mining	0	15	15
Solution mining of salt	180	165	345
Solution mining of potash	0	100	100
Subtotal	198	362	560
Total	N/A	N/A	6,258

N/A = Not Applicable.

Source: Environmental Protection Agency. *Class III Cost Analysis.* (May 1980).

The State program costs for all States to comply with this Subpart of the regulations are estimated to be $1.9 million over five years as shown in Table 10.

Class IV Wells. Until an underground injection facility receives an UIC permit issued pursuant to the Safe Drinking Water Act it is subject to the interim status requirements of the Resource Conservation and Recovery Act.[52] The Agency adopted this approach because the UIC program does not have the equivalent of an interim status period when owners or operators who dispose of hazardous waste by underground injection are subject to Federally enforceable standards. Enforcement of environmental controls under the UIC program must await: the development by states of programs for primary enforcement responsibility; the approval or disapproval of those programs by EPA; and the development of UIC programs by EPA in States which fail to develop and implement adequate programs for primary enforcement responsibility. EPA does not believe that UIC primary enforcement programs will be in place in all States on the effective date of these interim status regulations. Therefore, in order to provide control over underground injection of hazardous waste during the interim status period, as contemplated by RCRA, it is necessary to regulate underground injection under 40 CFR 265, Subpart R.

Table 10.—*Incremental Five-Year Costs to States, Class III Wells*

[In thousands of 1977 dollars]

	Total
Non-recurring:	
Developing state programs	72
Program hearings	23
Permitting existing sites	536
Permit hearings	76
Subtotal	709
Recurring:	
Quarterly Review	285
Annual Report	130
Enforcement	815
Subtotal	1,230
Total	1,939

Source: Environmental Protection Agency. *Class III Cost Analysis.* (May 1980).

[47] Environmental Protection Agency, *Class III Cost Analysis* (May, 1980).

[48] Temple, Barker and Sloane, *op. cit.*, Part I, p. II–23.

[49] *Ibid.*, Part I, p. II–27.

[50] *Ibid.*, Part I, p. III–6.

[51] *Ibid.*, Part I, p. III–8.

[52] 45 FR 33176.

Once an UIC program is promulgated by a state, Class IV wells which inject hazardous waste directly into an underground source of drinking water will be prohibited.[53] This prohibition is effective six months after the affective date of the program. Requirements for Class IV wells which inject above an underground source of drinking water are reserved.

Preliminary analysis, based on limited field work, suggests that there are between 5,000–10,000 wells that will meet the definition of Class IV. The "best estimate" is 7,500 wells.

In estimating costs EPA's consultant based its analysis on the expectation that large disposers—those injecting more than one thousand gallons per day—will pretreat their waste stream to remove the hazardous components, then transport the sludge to an off-site facility. Small disposers it is assumed, will transport the entire waste stream without prior treatment.[54] In revising the cost estimate to conform with the promulgated regulations EPA followed this convention.[55] In addition, EPA included costs for monitoring of injection fluids and quarterly reporting to the Director in order to present the costs of a comprehensive regulatory program. Such monitoring and reporting is not now required, but under consideration. To illustrate, one of the options for which the Agency has requested comments, in connection with permitting standards for hazardous waste management facilities, would require a demonstration that the anticipated impact upon groundwater" * * * will not adversely affect the health of persons or violate NPDWR based on the following information:

Injection volume and pressure * * *
Direction of ground water flow * * *
Monitoring up-gradient and down-gradient." [56]

It is expected that the cost to industry in the first five years of program operation will total $163 million. State costs are estimated at $1.2 million over this period.[57]

Class V Wells. Generally, wells falling into this class inject nonhazardous fluids into or above formations that contain underground sources of drinking water. Owners or operators of such wells are to notify the Director of the existence of any well under his control meeting the definition of Class V, and submit certain information within one year of the effective date of the UIC program. Within three years of such effective date the Director is to: submit certain information; assess the contamination potential of Class V wells; assess the available corrective alternatives and their environmental and economic consequences; and make recommendations for the most appropriate regulatory approaches and for remedial actions, where appropriate.[58]

Nonrecurring State costs for Class V wells are related to establishing the assessment program while annual costs relate to compiling, categorizing and analyzing the information collected. It is estimated that this effort will cost $5.2 to $7.2 million over a five year period.

Production Impact

Class II

EPA followed a seven step approach to the estimate of the impact of the Regulations on oil production.[59]

1. Determine the cost of compliance for each event combination.
2. Calculate the break-even point for each event combination.
3. Calculate the probability for each event combination.
4. Determine the expected value of fraction of wells shut down or unrealized, i.e., those producing below break-even point.
5. Determine the expected value of fraction of production lost due to shut down/unrealized wells.
6. *Number of wells shut down* = total number of wells under regulation × (sum of expected values of fraction of wells shut down/unrealized.
7. *Lost production* = total production from wells under regulation × (sum of expected value of fraction of lost production).

Previously, EPA estimated that approximately 12,000 barrels of oil per day would not be produced as a result of the regulations.[60] In the interim EPA's contractor reviewed the analysis and made several important changes.[61] First, the profit per barrel was revised from four to six dollars because the rapidly increasing price of crude oil rendered the earlier profit figure obsolete. Second, the capital recovery period was revised from ten years for all wells, to one and one-half years for new ones, and three for existing wells, to more accurately reflect current industry practice. This change represents a substantially more stringent assumption regarding the required profitability of associated producing wells when evaluated against the cost incurred in compliance with the Regulations. Third, the discount rate used in the calculation of the present value of future profits was increased from 10% to 13%. Again, this represents a more stringent criterion for determining whether the expenditure of funds in compliance with the Regulations is justified on the basis of future profits. All of the changes except that relating to profits tended to increase the impact on production compared to EPA's previous estimate.

The combined effect of those changes was to increase the estimate of production loss from 12,000 to 13,300 barrels per day (BPD).[62] The impact associated with each category of injection well is presented in Table 11. It is to be noted that the estimate of lost production is closely tied to profit rates, the distribution of profit per barrel among wells, and payback period. If profits are assumed to increase from six to ten dollars per barrel, which EPA believes to be a reasonable assumption, the estimated loss in production attributable to the regulations declines from thirteen thousand to five thousand BPD.[63] If, instead of applying a uniform profit of $6 per barrel, it is assumed that one-third of all wells earn $4 per barrel and two-thirds earn $10 per barrel, the loss in oil production increases from thirteen thousand to twenty thousand BPD.[64] If the required payback period is decreased from one and one-half to one year for new wells, and from three to two years for existing wells, the loss in production amounts to 29,000 BPD.[65]

[53] 40 CFR 122.36.
[54] *Ibid.*, Part II, p. III–5.
[55] U.S. Environmental Protection Agency. *Class IV Cost Analysis* (May 1980).
[56] 45 FR 33332.
[57] Environmental Protection Agency. *Class IV Cost Analysis* (May 1980).
[58] 40 CFR 146.51; 40 CFR 146.52.
[59] Booz, Allen and Hamilton, Inc., *Re-estimation of Impacts of Proposed Underground Injection Control Regulations on Crude Oil Production.* (April 30, 1980). Attachment 3, p. 11.
[60] 44 FR 23 758, April 20, 1979.
[61] Generally, Booz, Allen and Hamilton. *Re-estimation of Impacts . . .*, p. III–3.
[62] *Ibid.*, p. III–2.
[63] *Ibid.*, p. III–3.
[64] *Ibid.*, p. III–8.
[65] *Ibid.*, p. III–3.

Table 11.—*Production Loss Related to Type of Injection Well Subject to Regulation*

Type of well	Injection wells		Associated producing wells		Associated production loss (thousands BPD)		
	Shut-in	Not put into service	Shut-in	Not coverted to enhance recovery	Shut-in wells	Enhanced recovery not put into service	Total
Existing enhanced recovery	1,090		1,090		2.4		2.4
Existing salt water disposal	75		300		.4		.4
New enhanced recovery	40	2,470		2,510		10.3	10.3
New salt water disposal		15		60		.2	.2
Totals	1,205	2,485	1,390	2,570	2.8	10.5	13.3

Source: Booz, Allen and Hamilton, *Reestimation of Impacts of Proposed Underground Injection Control Regulations on Crude Oil Production.* (April 30, 1980), p. III–4.

In the aggregate the regulations are expected to have little effect on profits, prices, production, or employment. Imported oil prices are determined by the Organization of Petroleum Exporting Countries (OPEC), and domestic "new" oil is priced accordingly. With the expiration of controls on "old" oil in 1981, all domestically produced oil will be priced according to OPEC levels. Therefore it is reasonable to expect that the cost of compliance will be absorbed by oil firms.[66] In 1977 revenues of the oil industry were $82.5 billion.[67] The average annual cost of $113 million attributable to the regulations represents about one third of one percent of total revenues.

Based upon overall output per employee productivity figures, the loss of 13,300 barrels per day suggests a maximum potential reduction in employment of 600 employees. In practice the number of positions actually eliminated may approach zero, for two reasons: First, almost all of the lost production accrues to future wells not put into service. Since they are not yet in existence there are no existing jobs eliminated. Second, the remaining lost production of 2,700 BPD is distributed among fifteen hundred producing wells. Considering the widely dispersed impact it appears that few, if any, current jobs will be lost.[68]

On a regional level the impact will be more variable. In general, regions with (1) a higher proportion of stripper wells, (2) wells producing at a relatively low output, (3) a large number of abandonments, and (4) poor completion and abandonment practices, will be affected more than regions not so characterized. Based upon these types of considerations it appears that the impact of the regulations will be felt to a greater extent in the Illinois and Appalachian Basins. The least likely regions to experience an impact are the Rocky Mountain and the Gulf Coast. Between these extremes will fall California, East Texas and the Permian Basin.[69]

Class III[70]

The potential impact of the regulations is not expected to be significant, for the following reasons:

(1) For most industries the production from the sites subject to the regulations account for only a small proportion of domestic supply;

(2) For salt and Frasch sulfur production, compliance costs are relatively small; and

(3) Firms engaging in solution mining are diversified.

No loss of employment is expected to be caused by compliance with the regulations.

Reporting Impacts

Reporting requirements apply to all permit holders under Classes I and III, and to owners or operators of wells authorized by permit or rule under Class II. Owners or operators of Class II wells are to report once each year, while owners or operators of Class I and III wells are to report quarterly. Although not presently required, reporting costs have also been estimated for Class IV operators, as discussed earlier.

Total annual costs to owners and operators of Class I, II, and III wells are estimated to be $468,000. Owners and operators of Class IV wells are estimated to incur costs in the first year only of approximately $600,000 in submitting monitoring reports. They will not incur reporting costs beyond the first year because these wells are banned after six months from the time the UIC program becomes effective.

The State will review these reports. It will, in turn, make three types of reports to EPA: (1) Quarterly reports on the compliance status of major facilities (Classes I and IV) once the State program is effective; (2) annual reports on the operation of its program; and (3) "mid-course correction" reports, as described in the following section on program evaluation.

Annual State costs for the review of monitoring data for Classes I, II, and III, and for the submission of the quarterly and annual reports to EPA, are estimated to be about $1.0 million per year. These are recurring annual costs and do not include a cost of $221,000 incurred by the States during the first year only, to review Class IV monitoring reports. It is expected that the mid-course correction reports will require an insignificant amount of time to prepare, and no cost has been included for them.

EPA will review the quarterly and annual reports from the 57 jurisdictions at an estimated cost of $18,000 per year.

In summary, reporting costs during the first five years of program operation total $8.2 million, as follows:

- Owner/operators, $2.9 million.
- States, $5.2 million.
- EPA, $90 thousand.

Reporting costs are presented in additional detail in Table 12.

Evaluation Plan

In the preamble to the reproposed regulations,[71] EPA summarized its plan for evaluation of the UIC program and indicated it would provide a more detailed plan on promulgation. The discussion below summarizes the Agency's plan in this area.

EPA would like to be able to target the UIC requirements to those well types and geologic, geographic or hydrologic conditions, that have the greatest potential for groundwater contamination. EPA will evaluate the program and, based on its findings, may adjust the requirements of the UIC program.

[66] Booz, Allen and Hamilton, *Underground Injection Control Program. Industry Analysis of Class II and Class III Well Regulation.* (April 30, 1980), p. III–3.

[67] *Ibid.*, p. II–12.

[68] Booz, Allen and Hamilton. *Underground Injection Control Program. Industry Analysis* . . . (p. IV–2).

[69] *Ibid.*, p. 2; IV–4.

[70] *Ibid.*, p. III–14 ff.

[71] 44 FR 23752, April 20, 1979.

Table 12.—*Reporting Costs*

	Well class			
	I	II	III	IV
Well owner/operator:				
Reporting monitoring data:				
Reporting frequency per year	4	1	1	1
Unit time (hours)	8	1	8–16	4
Unit cost (dollars)	75	11–18	75–150	40
Number of wells/sites	[1]309	25,200	142	[2]7,500
Total cost per year ($ thousands)	23	278	67	[2]600
State:				
Review monitoring reports:				
Number reviewed per year	1,236	25,200	568	[3]15,000
Unit time (hours)	6	1	7	1
Unit cost (dollars)	90	18	105	15
Total cost per year ($ thousands)	100	454	60	[2]221
Quarterly report to EPA on compliance status:				
Number submitted per year	96	n.a.	n.a.	114
Unit time (hours)	18	n.a.	n.a.	40
Unit cost (dollars)	270	n.a.	n.a.	360
Total cost per year ($ thousands)	26	n.a.	n.a.	66
Annual report to EPA on program operation:				
Unit time (hours)	30–140	140	700	100
Unit cost (dollars)	400–2,000	2,400	1,625	2,400
Total cost per year ($ thousands)	10–49	77	26	137

Table 12.—*Reporting Costs*—Continued

	Well class			
	I	II	III	IV
Environmental Protection Agency:				
Review of quarterly report on compliance status:				
Number received	[illegible]	n.a.	n.a.	114
Unit time (hours)	4	n.a.	n.a.	4
Unit cost (dollars)	40	n.a.	n.a.	[illegible]
Total cost per year ($ thousands)	[illegible]	n.a.	n.a.	5
Review of Annual Report on Program Operation:				
Number reviewed	[illegible]	32	16	57
Unit time (hours)	4	16	[illegible]	4
Unit cost (dollars)	[illegible]	160	40	[illegible]
Total cost per year ($ thousands)	[illegible]	5	[illegible]	2

[1] The average number of wells in States which do not presently require reporting.

[2] Only two reports will be submitted since it is assumed that all injections of hazardous waste ceases within six months. Hence, there are no Class IV reporting costs to injectors after the first year.

n.a. = Not applicable.

The Agency evaluated two approaches for directly measuring the improvement in ground-water quality that would result from implementation of the UIC program and concluded that neither was a viable method of evaluating the program. The first approach was based on the drilling of monitoring wells in the immediate vicinity of a random sample of injection wells to determine the ambient ground-water quality. Because the expected failure rates (i.e., the fraction of wells expected to fail a mechanical integrity test) are small (estimated at 2–3% for Class II wells, for example) large sample sizes would be needed to measure the effect reliably. It was estimated that the Agency would need to sample 200 injection wells to measure the failure rates and a much larger sample, perhaps 1,000, to make inferences about what categories of wells are most likely to fail. Using the conservative assumption that at least two monitoring wells would generally be needed for each injection well, and that the cost of drilling a monitoring well would be on the order of $20,000, the total costs for the well drilling alone would be $8 million to sample 200 injection wells and $40 million to sample 1,000 wells. In addition to its extremely high cost, this approach has two other serious drawbacks. It provides no information on the effect of nearby wells in the area of review on groundwater or on the effectiveness of the UIC program in abating pollution from these wells. It also would not provide valid data on the effectiveness of the UIC program in ensuring that leaking injection wells are repaired. To obtain data on ground-water quality before and after program implementation, the sample on which the evaluation would be based would have to be drawn and known to the program managers before the program takes effect. There would, therefore, be no way to ensure that the treatment of the sampled injection wells was representative of the State programs as a whole. For these reasons, this approach was rejected.

The second direct approach that EPA evaluated is based on analysis of water from existing water wells (or other wells, such as existing monitoring wells) that happen to be located near injection wells. If a sample of such wells showed a significantly higher rate of contamination, for example by salinity, than a sample of wells further from injection wells, one could conclude that the injections wells were likely to be a cause of contamination. Similarly, if the rate of contamination were reduced after implementation of the UIC program, one could conclude that it had been effective. This approach would avoid the necessity of drilling monitoring wells, but it suffers from a number of serious drawbacks which have led EPA to reject it as well. First, it would be necessary in each case to perform a ground-water modeling exercise to determine whether contamination, if it existed, would have reached a given water well. Methods and data to do this routinely with sample sizes of hundreds or thousands do not exist. Second, we would not know when the contamination might have begun, so we would not know how far the plume of contamination would have traveled even if we have an adequate ground-water flow model for the area. Third, existing water wells would in many cases not be drawing from the depths and strata which may have been contaminated. Fourth, where contamination has in fact reached a water well, the well might well have been closed down without an adequate record, introducing an inherent bias. Fifth, it would be impossible to distinguish between contamination from an injection well and contamination from a nearby brine pit (perhaps abandoned). Sixth, it is not clear whether the population of injection wells with water wells located nearby is statistically representative of injection wells as a whole.

EPA also evaluated the possibility of using surface resistivity methods as part of an evaluation scheme to determine from the surface whether contamination had occurred. The evaluation included a field test of the method in an area where contamination by a Class II well had been alleged. EPA concluded that, at its present stage of development, the results of the method are not clear enough for routine use in a broad scale evaluation.

Because of the lack of valid and feasible means of evaluating the effect of the UIC program directly on ground-water quality, EPA has been forced in its evaluation plans to rely on an indirect set of measures of the need for and the effectiveness of the program. EPA will use the observed failure rates as its major evaluation tool. EPA will evaluate these failure rates and, based on its findings, make appropriate changes in the regulations.

Any such changes would be accomplished through amendments of these regulations and would involve full opportunity for public comment. EPA also would expect that the implementation of the UIC program would lead to an increased public awareness of the potential impacts of well injection on groundwater and hence to an increase in the number of reported cases of alleged contamination and to investigation and resolution of these incidents, thus improving the available data base on the direct impacts of injection wells on ground-water quality.

In addition to analysis of failure rates, EPA will also evaluate the administrative effectiveness of the program—whether permits are being issued as required, whether corrective action is in fact occurring when problems are discovered, and so forth.

The mechanisms which EPA will use to carry out these evaluations are the following:

For Classes I, II, III, IV, and V. Quarterly or annual reporting is required of both the owners and operators of wells and the States with primary enforcement responsibility for the program. This periodic reporting will allow the periodic assessment of the efficiency of the program in terms of whether the permits are being issued on such schedule, what the rate of permit violations are and whether the rates are increasing or decreasing, and whether State programs are performing adequately as measured by the conditions of State primacy.

In addition, the following will be required for specific categories of wells:

For injection wells in Classes I, II, and certain Class III wells, the regulations'

major requirements are periodic mechanical integrity tests and evaluation of wells in the area of review. EPA will conduct a "mid-course" evaluation of these two requirements on an ongoing basis as the Agency collects data from the States based on the first two years of program operations. The evaluation will provide information on the potential environmental problem posed by injection wells lacking mechanical integrity and by abandoned and producing wells that penetrate the zone of endangering influence associated with injection wells. It will also yield information on the costs and benefits of corrective action and analyze alternatives to the current requirement.

For other categories of Class III wells, the scheme presented above is not appropriate because the applicable regulatory requirements are quite different; these will be evaluated on a case-by-case basis.

For Class IV wells, EPA's evaluation will center on whether such wells are in fact identified and phased out when this is required by the regulations.

Evaluation of the UIC program's effectiveness with respect to *Class V wells* is premature at this time.

EPA considered several alternatives on the timing of the data submission and for "mid-course" evaluation of the requirement for mechanical integrity testing and for the area of review. The considerations that were balanced included the burden on the States in supplying the data, the desire to make any needed corrections in the regulations as quickly as possible, and the need for a sufficiently large and representative sample of data. The reproposal provided for submission of data after the first year of operation of the State programs. Concern developed, however, that one year's operation might be an arbitrary limit. It would be unrepresentative because it is too short for two reasons: (1) Practical experience with program implementation indicates that an initial period of time is required during which both program staff and the regulated community gains experience with the new procedures and requirements; and (2) because five years are allowed for mechanical integrity tests for existing injection wells (where required), it is likely that relatively few of these actions will occur in the first year. Conversely, one year's operation may not provide enough data with which to conduct a statistically valid evaluation of the area of review and mechanical integrity portions of the regulation.

The Agency, therefore, selected an alternative which it believes is an appropriate compromise. The requirements for the evaluation of the major provisions applicable to Classes I, II, and certain Class III wells are specified in 40 CFR 122.18(c)(4)(ii) and 146.

The State Director is to submit this data during the first two full years of operation of the State program, at six-month intervals. The data is to include information on the hydrogeological environment, the numbers and types of wells in the area of review and any remedial action required by the Director, and the results of mechancial integrity tests conducted pursuant to the regulations.

This alternative ensures the data will cover a representative period of program operation and also enable EPA to begin to develop data analysis procedures and to draw appropriate conclusions about program effectiveness as soon as it gets a large enough sample of data.

The Agency originally proposed to apply the evaluation of mechancial integrity and area of review requirements solely to Class II wells because it was here that major questions about the requirements had been raised. After further consideration, the Agency decided to evaluate the requirements for Class I and certain Class III wells for which the requirements are similar.

OMB Review

The sections of these regulations pertaining to recordkeeping and reporting will be submitted to the Office of Management and Budget for review in light of the requirements of the Federal Reports Act, 44 U.S.C. Sec. 3501 *et seq.*

(Secs. 1421, 1422, 1423, 1431, 1445, 1447, 1450, Safe Drinking Water Act, as amended, 42 U.S.C. 300(f) et seq.)

Douglas M. Costle,

Administrator.

June 17, 1980.

Part 146 is added to Title 40 to read as set forth below:

PART 146—UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS

Subpart A—General Provisions

Sec.

146.01 Applicability and scope.
146.02 Law authorizing these regulations.
146.03 Definitions.
146.04 Criteria for exempted aquifers.
146.05 Classification of injection wells.
146.06 Area of review.
146.07 Corrective action.
146.08 Mechanical integrity.
146.09 Criteria for establishing permitting priorities.
146.10 Plugging and abandoning Class I–III wells.

Subpart B—Criteria and Standards Applicable to Class I Wells

146.11 Applicability.
146.12 Construction requirements.
146.13 Operating, monitoring and reporting requirements.
146.14 Information to be considered by the Director.
146.15 Mid course evaluation requirements.

Subpart C—Criteria and Standards Applicable to Class II Wells

146.21 Applicability.
146.22 Construction requirements.
146.23 Operating, monitoring, and reporting requirements.
146.24 Information to be considered by the director.
146.25 Mid course evaluation requirements.

Subpart D—Criteria and Standards Applicable to Class III Wells

146.31 Applicability.
146.32 Construction requirements.
146.33 Operating, monitoring and reporting requirements.
146.34 Information to be considered by the Director.
146.35 Mid course evaluation requirements.

Subpart E—Criteria and Standards Applicable to Class IV Injection Wells

Subpart F—Criteria and Standards Applicable to Class V Injection Wells

146.51 Applicability.
146.52 Inventory and Assessment.

Authority: Secs. 1421, 1422, 1423, 1431, 1445, 1447, and 1450 of the Safe Drinking Water Act, as amended, 42 U.S.C. 300(f) et. seq.

Subpart A—General Provisions

§ 146.01 Applicability and scope.

(a) This Part sets forth technical criteria and standards for the Underground Injection Control Program. This part should be read in conjunction with 40 CFR Parts 122, 123, and 124 which also apply to UIC programs. 40 CFR Part 122 defines the regulatory framework of EPA administered permit programs. 40 CFR Part 123 describes the elements of an approvable State program and procedures for EPA approval of State participation in the permit programs. 40 CFR Part 124 describes the procedures the Agency will use for issuing permits under the covered programs. Certain of these procedures will also apply to State-administered programs as specified in 40 CFR Part 123.

(b) Upon the approval, partial approval or promulgation of a State UIC program by the Administrator, any underground injection which is not authorized by the Director by rule or by permit is unlawful.

§ 146.02 Law authorizing these regulations.

The laws authorizing these regulations and all other UIC program regulations are referenced in 40 CFR part 122. They include Sections 1421, 1422, 1423, 1431, 1445, 1447 and 1450 of the Public Health Service Act as amended by the Safe Drinking Water Act ("SDWA") (Pub. L. 93–523) and by the SDWA Amendments of 1977 (Pub. L. 95–190).

§ 146.03 Definitions.

The following definitions apply to the underground injection control program.

Abandoned well means a well whose use has been permanently discontinued or which is in a state of disrepair such that it cannot be used for its intended purpose or for observation purposes.

Administrator means the Administrator of the United States Environmental Protection Agency, or an authorized representative.

Application means the EPA standard national forms for applying for a permit, including any additions, revisions or modifications to the forms; or forms approved by EPA for use in approved States, including any approved modifications or revisions. For RCRA, application also includes the information required by the Director under § 122.25 (contents of Part B of the RCRA application).

Aquifer means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

Area of review means the area surrounding an "injection well" described according to the criteria set forth in § 146.06.

Casing means a heavy metal (steel or iron) pipe or tubing of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent loss of drilling mud into porous ground, or to prevent water, gas, or other fluid from entering the hole.

Catastrophic collapse means the sudden and utter failure of overlying "strata" caused by removal of underlying materials.

Cementing means the operation whereby a cement slurry is pumped into a drilled hole and/or forced behind the casing.

Confining bed means a body of impermeable or distinctly less permeable material stratigraphically adjacent to one or more aquifers.

Confining zone means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone.

Contaminant means any physical, chemical, biological, or radiological substance or matter in water.

Director means the Regional Administrator or the State Director, as the context requires, or an authorized representative. When there is no approved State program, and there is an EPA administered program, "Director" means the Regional Administrator. When there is an approved State program, "Director" normally means the State Director. In some circumstances, however, EPA retains the authority to take certain actions even where there is an approved State program. (For example, when EPA issued an NPDES permit prior to the approval of a State program, EPA may retain jurisdiction over that permit after program approval, see § 123.69.) In such cases, the term "Director" means the Regional Administrator and not the State Director.

Disposal well means a well used for the disposal of waste into a subsurface stratum.

Effective date of a UIC program means the date that a State UIC program is approved or established by the Administrator.

Environmental Protection Agency ("EPA") means the United States Environmental Protection Agency.

EPA means the United States "Environmental Protection Agency."

Exempted aquifer means an aquifer or its portion that meets the criteria in the definition of "underground source of drinking water" but which has been exempted according to the procedures of § 122.35(b).

Existing injection well means an "injection well" other than a "new injection well."

Facility or activity means any "HWM facility," UIC "injection well," NPDES "point source," or State 404 dredge and fill activity, or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the RCRA, UIC, NPDES, or 404 programs.

Fault means a surface or zone of rock fracture along which there has been displacement.

Flow rate means the volume per time unit given to the flow of gases or other fluid substance which emerges from an orifice, pump, turbine or passes along a conduit or channel.

Fluid means material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state.

Formation means a body of rock characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.

Formation fluid means "fluid" present in a "formation" under natural conditions as opposed to introduced fluids, such as drilling mud.

Generator means any person, by site location, whose act or process produces hazardous waste identified or listed in 40 CFR Part 261.

Ground water means water below the land surface in a zone of saturation.

Hazardous waste means a hazardous waste as defined in 40 CFR 261.3.

Hazardous Waste Management facility ("HWM facility") means all contiguous land, and structures, other appurtenances, and improvements on the land used for treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (for example, one or more landfills, surface impoundments, or combination of them).

HWM facility means "Hazardous Waste Management facility."

Injection well means a "well" into which "fluids" are being injected.

Injection zone means a geological "formation", group of formations, or part of a formation receiving fluids through a well.

Lithology means the description of rocks on the basis of their physical and chemical characteristics.

Owner or operator means the owner or operator of any facility or activity subject to regulation under the RCRA, UIC, NPDES, or 404 programs.

Packer means a device lowered into a well which can be expanded to produce a water-tight seal.

Permit means an authorization, license, or equivalent control document issued by EPA or an "approved State" to implement the requirements of this part and Parts 122, 123 and 124. Permit does not include RCRA interim status (§ 122.23), UIC authorization by rule (§ 122.37), or any permit which has not yet been the subject of final agency action, such as a "draft permit" or a "proposed permit."

Plugging means the act or process of stopping the flow of water, oil, or gas in "formations" penetrated by a borehole or "well."

Plugging record means a systematic listing of permanent or temporary abandonment of water, oil, gas, test, exploration and waste injection wells, and may contain a well log, description of amounts and types of plugging material used, the method employed for plugging, a description of formations which are sealed and a graphic log of the well showing formation location,

formation thickness, and location of plugging structures.

Pressure means the total load or force per unit area acting on a surface.

Radioactive Waste means any waste which contains radioactive material in concentrations which exceed those listed in 10 CFR Part 20, Appendix B, Table II, Column 2, or exceed the "Criteria for Identifying and Applying Characteristics of Hazardous Waste and for Listing Hazardous Waste" in 40 CFR Part 261, whichever is applicable.

RCRA means the Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act of 1976 (Pub. L. 94–580, as amended by Pub. L. 95–609, 42 U.S.C. 6901 et seq.).

SDWA means the Safe Drinking Water Act (Pub. L. 95–523, as amended by Pub. L. 95–190, 42 U.S.C. 300(f) *et seq.).*

Site means the land or water area where any facility or activity is physically located or conducted, including adjacent land used in connection with the facility or activity.

Sole or principal source aquifer means an aquifer which has been designated by the Administrator pursuant to sections 1424 (a) or (e) of the SDWA.

State Director means the chief administrative officer of any State or interstate agency operating an approved program, or the delegated representative of the State Director. If responsibility is divided among two or more State or interstate agencies, "State Director" means the chief administrative officer of the State or interstate agency authorized to perform the particular procedure or function to which reference is made.

Stratum (plural *strata*) means a single sedimentary bed or layer, regardless of thickness, that consists of generally the same kind of rock material.

Subsidence means the lowering of the natural land surface in response to: Earth movements; lowering of fluid pressure; removal of underlying supporting material by mining or solution of solids, either artificially or from natural causes; compaction due to wetting (Hydrocompaction); oxidation of organic matter in soils; or added load on the land surface.

Surface casing means the first string of well casing to be installed in the well.

Total dissolved solids ("TDS") means the total dissolved (filterable) solids as determined by use of the method specified in 40 CFR Part 136.

UIC means the Underground Injection Control program under Part C of the Safe Drinking Water Act, including an "approved program."

Underground injection means a "well injection."

Underground source of drinking water ("USDW") means an "aquifer" or its portion:

(1)(i) Which supplies drinking water for human consumption; or

(ii) In which the ground water contains fewer than 10,000 mg/1 "total dissolved solids;" and

(2) Which is not an "exempted aquifer."

USDW means "underground source of drinking water."

Well means a bored, drilled or driven shaft, or a dug hole, whose depth is greater than the largest surface dimension.

Well injection means the subsurface emplacement of fluids through a bored, drilled or driven well; or through a dug well, where the depth of the dug well is greater than the largest surface dimension.

Well log means a log obtained from a well, showing such information as resistivity, radioactivity, spontaneous potential, and acoustic velocity as a function of depth.

Well plug means a watertight and gastight seal installed in a borehole or well to prevent movement of fluids.

Well record means a concise statement of the available data regarding a well, such as a scout ticket; a full history or day-by-day account of a well, from the day the well was surveyed to the day production ceased.

Well stimulation means several processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for wastewater to move more readily into the formation, and includes (1) surging, (2) jetting, (3) blasting, (4) acidizing, (5) hydraulic fracturing.

Well monitoring means the measurement, by on-site instruments or laboratory methods, of the quality of water in a well.

§ 146.04 Criteria for exempted aquifers.

An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in § 146.03 may be determined under 40 CFR 122.35 to be an "exempted aquifer" if it meets the following criteria:

(a) It does not currently serve as a source of drinking water; and

(b) It cannot now and will not in the future serve as a source of drinking water because:

(1) It is mineral, hydrocarbon or geothermal energy producing;

(2) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;

(3) It is so contaminated that it would be economically ot technologically impractical to render that water fit for human consumption; or

(4) It is located over a Class III well mining area subject to subsidence or catastrophic collapse.

§ 146.05 Classification of injection wells.

Injection wells are classified as follows:

(a) *Class I.* (1) Wells used by generators of hazardous wastes or owners or operators of hazardous waste management facilities to inject hazardous waste, other than Class IV wells.

(2) Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

(b) *Class II.* Wells which inject fluids:

(1) Which are brought to the surface in connection with conventional oil or natural gas production;

(2) For enhanced recovery of oil or natural gas; and

(3) For storage of hydrocarbons which are liquid at standard temperature and pressure.

(c) *Class III.* Wells which inject for extraction of minerals or energy, including:

(1) Mining of sulfur by the Frasch process;

(2) Solution mining of minerals;

Note.—Solution mining of minerals includes sodium chloride, potash, phosphate, copper, uranium and any other mineral which can be mined by this process.

(3) in-situ combustion of fossil fuel: and

Note.—Fossil fuels includes coal, tar sands, oil shale and any other fossil fuel which can be mined by this process.

(4) recovery of geothermal energy to produce electric power.

Note.—Class III wells include the recovery of geothermal energy to produce electric power but do not include wells used in heating or aquaculture which fall under Class V.

(d) *Class IV.* Wells used by generators of hazardous wastes or of radioactive wastes, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous wastes or radioactive wastes into or above a formation which within one quarter mile of the well contains an underground source of drinking water.

(e) *Class V.* Injection wells not included in Class I, II, III, or IV.

Note.—Class V wells includes:

(1) Air conditioning return flow wells used to return to the supply aquifer the water used for heating or cooling in a heat pump;

(2) Cesspools or other devices that receive wastes, which have an open bottom and sometimes have perforated sides. The UIC requirements do not apply to single family residential cesspools;

(3) Cooling water return flow wells used to inject water previously used for cooling;

(4) Drainage wells used to drain surface fluid, primarily storm runoff, into a subsurface formation;

(5) Dry wells used for the injection of wastes into a subsurface formation;

(6) Recharge wells used to replenish the water in an aquifer;

(7) Salt water intrusion barrier wells used to inject water into a fresh water aquifer to prevent the intrusion of salt water into the fresh water;

(8) Sand backfill wells used to inject a mixture of water and sand, mill tailings or other solids into mined out portions of subsurface mines;

(9) Septic system wells used:

(i) To inject the waste or effluent from a multiple dwelling, business establishment, community or regional business establishment septic tank; or

(ii) For a multiple dwelling, community or regional cesspool. The UIC requirements do not apply to single family residential waste disposal systems;

(10) Subsidence control wells (not used for the purpose of oil or natural gas production) used to inject fluids into a non-oil or gas producing zone to reduce or eliminate subsidence associated with the overdraft of fresh water;

(11) Wells used for the storage of hydrocarbons which are gases at standard temperature and pressure;

(12) Geothermal wells used in heating and aquaculture;

(13) Nuclear disposal wells.

§ 146.06 Area of Review.

The area of review for each injection well or each field, project or area of the State shall be determined according to either paragraph (a) or (b) of this section. The Director may solicit input from the owners or operators of injection wells within the State as to which method is most appropriate for each geographic area or field.

(a) *Zone of endangering influence.* The zone of endangering influence shall be that area the radius of which is the lateral distance from an injection well, field or project in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water. Computation of the zone of endangering influence may be based upon the parameters listed below and should be calculated for an injection time period equal to the expected life of the injection well or pattern. The following modified Theis equation illustrates one form which the mathematical model may take.

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$$r = \left(\frac{2.25\ K\ H\ t}{S\ 10^{X}} \right)^{1/2}$$

where:

$$X = \frac{4\pi KH \left(h_w - h_{b_o} \times SpG_b \right)}{2.3\ Q}$$

r = Radius of endangering influence from injection well (length)

K = Hydraulic conductivity of the injection zone (length/time)

H = Thickness of the injection zone (length)

t = Time of injection (time)

S = Storage coefficient (dimensionless)

Q = Injection rate (volume/time)

h_{b_o} = Observed original hydrostatic head of injection zone (length) measured from the base of the lowest underground source of drinking water

h_w = Hydrostatic head of underground source of drinking water (length) measured from the base of the lowest underground source of drinking water

SpG_b = Specific gravity of fluid in the injection zone (dimensionless)

π = 3.142 (dimensionless).

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The above equation is based on the following assumptions:

(1) The injection zone is homogenous and isotropic;

(2) The injection zone has infinite areal extent;

(3) The injection well penetrates the entire thickness of the injection zone;

(4) The well diameter is infinitesimal compared to "r" when injection time is longer than a few minutes; and

(5) The emplacement of fluid into the injection zone creates instantaneous increase in pressure.

Other models may be used as appropriate for different situations encountered in the field or where the model assumptions match more closely those situations.

(b) *Fixed Radius.* A fixed radius around the well, field or project of not less than one-fourth (¼) mile may be used. In determining the fixed radius, the following factors shall be taken into consideration: Chemistry of injected and formation fluids; hydrogeology; population and ground-water use and dependence; and historical practices in the area.

(c) If the area of review is determined by a mathematical model pursuant to paragraph (a) of this section, the permissible radius is the result of such calculation even if it is less than one-fourth (¼) mile.

§ 146.07 Corrective Action.

In determining the adequacy of corrective action proposed by the applicant under 40 CFR 122.44 and in determining the additional steps needed to prevent fluid movement into underground sources of drinking water, the following criteria and factors shall be considered by the Director:

(a) Toxicity and volume of the injected fluid;

(b) Toxicity of native fluids or by-products of injection;

(c) Potentially affected population;

(d) Geology;

(e) Hydrology;

(f) History of the injection operation;

(g) Completion and plugging records;

(h) Abandonment procedures in effect at the time the well was abandoned; and

(i) Hydraulic connections with underground sources of drinking water.

§ 146.08 Mechanical Integrity

(a) An injection well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

(b) One of the following tests must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section.

(1) Monitoring of annulus pressure; or

(2) Pressure test with liquid or gas.

(c) One of the following methods must be used to determine the absence of significant fluid movement under paragraph (a)(2) of this section:

(1) For Class II only, well records demonstrating the presence of adequate cement to prevent such migration; or

(2) The results of a temperature or noise log.

(d) The Director may allow the use of a test to demonstrate mechanical integrity other than those listed in paragraphs (b) and (c)(2) of this section with the written approval of the Administrator. To obtain approval, the Director shall submit a written request to the Administrator, which shall set forth the proposed test and all technical data supporting its use. The Administrator shall approve the request if it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator shall be published in the **Federal Register** and may be used in all States unless its use is restricted at the time of approval by the Administrator.

(e) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director shall apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director shall review monitoring and other test data submitted since the previous evaluation.

§ 146.09 Criteria for Establishing Permitting Priorities.

In determining priorities for setting times for owners or operators to submit applications for authorization to inject under the procedures of § 122.38 or § 123.4(g), the Director shall base these priorities upon consideration of the following factors:

(a) Injection wells known or suspected to be contaminating underground sources of drinking water;

(b) Injection wells known to be injecting fluids containing hazardous contaminants;

(c) Likelihood of contamination of underground sources of drinking water;

(d) Potentially affected population;

(e) Injection wells violating existing State requirements;

(f) Coordination with the issuance of permits required by other State or Federal permit programs;

(g) Age and depth of the injection well; and

(h) Expiration dates of existing State permits, if any.

§ 146.10 Plugging and Abandoning Class I–III Wells.

(a) Prior to abandoning Class I–III wells the well shall be plugged with cement in a manner which will not allow the movement of fluids either into or between underground sources of drinking water.

(b) Placement of the cement plugs shall be accomplished by one of the following:

(1) The Balance Method;

(2) The Dump Bailer Method; or

(3) The Two-Plug Method.

(c) The well to be abandoned shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director, prior to the placement of the cement plug(s).

(d) The plugging and abandonment plan required in 40 CFR 122.42(f) and 122.41(e) shall, in the case of a Class III well field which underlies or is in an aquifer which has been exempted under 40 CFR 146.04, also demonstrate that no movement of contaminants from the mined zone into an underground source of drinking water will occur. The Director shall prescribe aquifer cleanup and monitoring where he deems it necessary and feasible to insure that no migration of contaminants from the mined zone into an underground source of drinking water will occur.

Subpart B—Criteria and Standards Applicable to Class I Wells

§ 146.11 Applicability.

This subpart establishes criteria and standards for underground injection control programs to regulate Class I wells.

§ 146.12 Construction Requirements.

(a) All Class I wells shall be sited in such a fashion that they inject into a formation which is beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

(b) All Class I wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the

well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, and axial loading;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluid, formation fluids, and temperatures;

(6) Lithology of injection and confining intervals; and

(7) Type or grade of cement.

(c) All Class I injection wells, except those municipal wells injecting non-corrosive wastes, shall inject fluids through tubing with a packer set immediately above the injection zone, or tubing with an approved fluid seal as an alternative. The tubing, packer, and fluid seal shall be designed for the expected service.

(1) The use of other alternatives to a packer may be allowed with the written approval of the Director. To obtain approval, the operator shall submit a written request to the Director, which shall set forth the proposed alternative and all technical data supporting its use. The Director shall approve the request if the alternative method will reliably provide a comparable level of protection to underground sources of drinking water. The Director may approve an alternative method solely for an individual well or for general use.

(2) In determining and specifying requirements for tubing, packer, or alternatives the following factors shall be considered:

(i) Depth of setting;

(ii) Characteristics of injection fluid (chemical content, corrosiveness, and density);

(iii) Injection pressure;

(iv) Annular pressure;

(v) Rate, temperature and volume of injected fluid; and

(vi) Size of casing.

(d) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class I wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a qualified log analyst and submitted to the Director. At a minimum, such logs and tests shall include:

(1) Deviation checks on all holes constructed by first drilling a pilot hole, and then enlarging the pilot hole by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling.

(2) Such other logs and tests as may be needed after taking into account the availability of similar data in the area of the drilling site, the construction plan, and the need for additional information, that may arise from time to time as the construction of the well progresses. In determining which logs and tests shall be required, the following logs shall be considered for use in the following situations:

(i) For surface casing intended to protect underground sources of drinking water:

(A) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and

(B) A cement bond, temperature, or density log after the casing is set and cemented.

(ii) For intermediate and long strings of casing intended to facilitate injection:

(A) Resistivity, spontaneous potential, porosity, and gamma ray logs before the casing is installed;

(B) Fracture finder logs; and

(C) A cement bond, temperature, or density log after the casing is set and cemented.

(e) At a minimum, the following information concerning the injection formation shall be determined or calculated for new Class I wells:

(1) Fluid pressure;

(2) Temperature;

(3) Fracture pressure;

(4) Other physical and chemical characteristics of the injection matrix; and

(5) Physical and chemical characteristics of the formation fluids.

§ 146.13 Operating, Monitoring and Reporting Requirements.

(a) *Operating Requirements.* Operating requirements shall, at a minimum, specify that:

(1) Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone, initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.

(3) Unless an alternative to a packer has been approved under § 146.12(c), the annulus between the tubing and the long string of casings shall be filled with a fluid approved by the Director and a pressure, also approved by the Director, shall be maintained on the annulus.

(b) *Monitoring Requirements.* Monitoring requirements shall, at a minimum, include:

(1) The analysis of the injected fluids with sufficient frequency to yield representative data of their characteristics;

(2) Installation and use of continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing;

(3) A demonstration of mechanical integrity pursuant to § 146.08 at least once every five years during the life of the well; and

(4) The type, number and location of wells within the area of review to be used to monitor any migration of fluids into and pressure in the underground sources of drinking water, the parameters to be measured and the frequency of monitoring.

(c) *Reporting Requirements.* Reporting requirements shall, at a minimum, include:

(1) Quarterly reports to the Director on:

(i) The physical, chemical and other relevant characteristics of injection fluids;

(ii) Monthly average, maximum and minimum values for injection pressure, flow rate and volume, and annular pressure; and

(iii) The results of monitoring prescribed under subparagraph (b)(4) of this section.

(2) Reporting the results, with the first quarterly report after the completion, of:

(i) Periodic tests of mechanical integrity;

(ii) Any other test of the injection well conducted by the permittee if required by the Director; and

(iii) Any well work over.

§ 146.14 Information to be Considered by the Director.

This section sets forth the information which must be considered by the Director in authorizing Class I wells. For an existing or converted new Class I well the Director may rely on the existing permit file for those items of information listed below which are current and accurate in the file. For a newly drilled Class I well, the Director shall require the submission of all the information listed below. For both existing and new Class I wells certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting

agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit all the information in this Section must be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class I well to operate or the construction or conversion of a new Class I well the Director shall consider the following:

(1) Information required in 40 CFR 122.4 and 122.38(c);

(2) A map showing the injection well(s) for which a permit is sought and the applicable area of review. Within the area of review, the map must show the number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells and other pertinent surface features including residences and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;

(3) A tabulation of data on all wells within the area of review which penetrate into the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;

(4) Maps and cross sections indicating the general vertical and lateral limits of all underground sources of drinking water within the area of review, their position relative to the injection formation and the direction of water movement, where known, in each underground source of drinking water which may be affected by the proposed injection;

(5) Maps and cross sections detailing the geologic structure of the local area;

(6) Generalized maps and cross sections illustrating the regional geologic setting;

(7) Proposed operating data:

(i) Average and maximum daily rate and volume of the fluid to be injected;

(ii) Average and maximum injection pressure; and

(iii) Source and an analysis of the chemical, physical, radiological and biological characteristics of injection fluids;

(8) Proposed formation testing program to obtain an analysis of the chemical, physical and radiological characteristics of and other information on the receiving formation;

(9) Proposed stimulation program;

(10) Proposed injection procedure;

(11) Engineering drawings of the surface and subsurface construction details of the system;

(12) Contingency plans to cope with all shut-ins or well failures so as to prevent migration of fluids into any underground source of drinking water;

(13) Plans (including maps) for meeting the monitoring requirements in § 146.13(b);

(14) For wells within the area of review which penetrate the injection zone but are not properly completed or plugged, the corrective action proposed to be taken under 40 CFR 122.44;

(15) Construction procedures including a cementing and casing program, logging procedures, deviation checks, and a drilling, testing, and coring program; and

(16) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well as required by 40 CFR 122.42(a).

(b) Prior to granting approval for the operation of a Class I well the Director shall consider the following information:

(1) All available logging and testing program data on the well;

(2) A demonstration of mechanical integrity pursuant to § 146.08;

(3) The actual operating data;

(4) The results of the formation testing program;

(5) The actual injection procedure;

(6) The compatibility of injected waste with fluids in the injection zone and minerals in both the injection zone and the confining zone; and

(7) The status of corrective action on defective wells in the area of review.

(c) Prior to granting approval for the plugging and abandonment of a Class I well the Director shall consider the following information:

(1) The type and number of plugs to be used;

(2) The placement of each plug including the elevation of the top and bottom;

(3) The type and grade and quantity of cement to be used;

(4) The method for placement of the plugs; and

(5) The procedure to be used to meet the requirements of § 146.10(c).

§ 146.15 Mid-course evaluation requirements.

In compliance with 40 CFR 122.18(c)(4)(c)(ii) the data to be submitted on each Class I permit at six month intervals during the first two years of operation of the State program shall at a minimum include the following:

(a) The data required in § 146.14(a)(1);

(b) The data required in § 146.14(a)(3) including, under location, the distance and direction from the injection well;

(c) The depth to the top and bottom of any USDW;

(d) The distance to the nearest down-gradient water supply well;

(e) A description of the geology and hydrology of the area;

(f) The construction characteristics of the well;

(g) The corrective action proposed as well as that performed;

(h) The type and results of all mechanical integrity tests reported to the Director; and

(i) Any reporting to the Director under § 122.41(d).

Subpart C—Criteria and Standards Applicable to Class II Wells

§ 146.21 Applicability.

This subpart establishes criteria and standards for underground injection control programs to regulate Class II wells.

§ 146.22 Construction requirements.

(a) All new Class II wells shall be sited in such a fashion that they inject into a formation which has confining zones that are free of known open faults or fractures within the area of review.

(b) All Class II injection wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, and axial loading;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluid and formation fluids;

(6) Lithology of injection and confining zones; and

(7) Type and grade of cement.

(c) The requirements in paragraph (b) of this section need not apply to existing or newly converted Class II wells located in existing fields if:

(1) Regulatory controls for casing and cementing existed for those wells at the time of drilling and those wells are in compliance with those controls; and

(2) Well injection will not result in the movement of fluids into an underground

source of drinking water so as to create a significant risk to the health of persons.

(d) The requirements in paragraph (b) of this section need not apply to newly drilled wells in existing fields if:

(1) They meet the requirements of the State for casing and cementing applicable to that field at the time of submission of the State program to the Administrator; and

(2) Well injection will not result in the movement of fluids into an underground source of drinking water so as to create a significant risk to the health of persons.

(e) Where a State did not have regulatory controls for casing and cementing prior to the time of the submission of the State program to the Administrator, the Director need not apply the casing and cementing requirements in paragraph (b) of this section if he submits as a part of his application for primacy, an appropriate plan for casing and cementing of existing, newly converted, and newly drilled wells in existing fields, and the Administrator approves the plan.

(f) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class II wells. A descriptive report interpreting the results of these logs and tests shall be prepared by a qualified log analyst and submitted to the Director. At a minimum, these logs and tests shall include:

(1) Deviation checks on all holes constructed by first drilling a pilot hole and then enlarging the pilot hole, by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.

(2) Such other logs and tests as may be needed after taking into account the availability of similar data in the area of the drilling site, the construction plan, and the need for additional information that may arise from time to time as the construction of the well progresses. In determining which logs and tests shall be required the following shall be considered by the Director in setting logging and testing requirements:

(i) For surface casing intended to protect underground sources of drinking water:

(A) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and

(B) A cement bond, temperature, or density log after the casing is set and cemented.

(ii) For intermediate and long strings of casing intended to facilitate injection:

(A) Resistivity, spontaneous potential, porosity, and gamma ray logs before the casing is installed;

(B) Fracture finder logs; and

(C) A cement bond, temperature, or density log after the casing is set and cemented.

(g) At a minimum, the following information concerning the injection formation shall be determined or calculated for new Class II wells:

(1) Fluid pressure;

(2) Temperature;

(3) Fracture pressure;

(4) Other physical and chemical characteristics of the injection zone; and

(5) Physical and chemical characteristics of the formation fluids.

§ 146.23 Operating, monitoring, and reporting requirements.

(a) *Operating Requirements.* Operating requirements shall, at a minimum, specify that:

(1) Except during well stimulation for enhanced recovery wells, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case, shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore shall be prohibited.

(b) *Monitoring Requirements.* Monitoring requirements shall, at a minimum, include:

(1) Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics;

(2) Monitoring of injection pressure, flow rate, and cumulative volume at least with the following frequencies:

(i) Weekly for produced fluid disposal operations;

(ii) Monthly for enhanced recovery operations;

(iii) Daily during the injection of liquid hydrocarbons and injection for withdrawal of stored hydrocarbons; and

(iv) Daily during the injection phase of cyclic steam operations;

(3) A demonstration of mechanical integrity pursuant to § 146.08 at least once every five years during the life of the injection well;

(4) Maintenance of the results of all monitoring until the next permit review (see 40 CFR 122.42(e)); and

(5) Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.

(c) *Reporting Requirements.*

(1) Reporting requirements shall, at a minimum include an annual report to the Director summarizing the results of the monitoring required under paragraph (b) of this section. Previously submitted information may be included by reference.

(2) Owners or operators of hydrocarbon storage and enhanced recovery projects may report on a field or project basis rather than an individual well basis where manifold monitoring is used.

§ 146.24 Information to be considered by the director.

This section sets forth the information which must be considered by the Director in authorizing Class II wells. Certain maps, cross-sections, tabulations of wells within the area of review, and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this Section is to be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class II well to operate or the construction or conversion of a new Class II well the Director shall consider the following:

(1) Information required in 40 CFR 122.4 and 122.38(c);

(2) A map showing the injection well(s) for which a permit is sought and the applicable area of review. Within the area of review, the map must show the number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes and water wells. The map should also show faults, if known or suspected. Only wells of public record are required to be included on this map. This requirement does not apply to existing Class II wells; and

(3) A tabulation of data on all wells within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any

additional information the Director may require. This requirement does not apply to existing Class II wells.

(4) Proposed operating data:

(i) Average and maximum daily rate and volume of fluids to be injected;

(ii) Average and maximum injection pressure; and

(iii) Source, and an analysis of the chemical, physical, radiological and biological characteristics of the injection fluid;

(5) Appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and lateral extent;

(6) Geologic name, lateral extent and depth to top and bottom of all underground sources of drinking water which may be affected by the injection;

(7) Engineering drawings of the surface and subsurface construction details of the system;

(8) Proposed formation testing program;

(9) Proposed stimulation program;

(10) Proposed injection procedure;

(11) Contingency plans to cope with all shut-ins or well failures so as to prevent migration of contaminating fluids into any underground source of drinking water;

(12) Plans for meeting the monitoring requirements of § 146.23(b);

(13) In the case of new injection wells, the corrective action proposed to be taken by the applicant under 40 CFR 122.44;

(14) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well as required by 40 CFR 122.42(g).

(b) Prior to granting approval for the operation of a Class II well the Director shall consider the following information:

(1) All available logging and testing program data on the well;

(2) A demonstration of mechanical integrity pursuant to § 146.08;

(3) The actual operating data;

(4) The results of the formation testing program;

(5) The actual injection procedure; and

(6) For new wells the status of corrective action on defective wells in the area of review.

(c) Prior to granting approval for the plugging and abandonment of a Class II well the Director shall consider the following information:

(1) The type, and number of plugs to be used;

(2) The placement of each plug including the elevation of top and bottom;

(3) The type, grade, and quantity of cement to be used;

(4) The method of placement of the plugs; and

(5) The procedure to be used to meet the requirements of § 146.10(c).

§ 146.25 Mid-course evaluation requirements.

(a) In compliance with 40 CFR 122.18(c)(4)(C)(ii) the data to be submitted on each new Class II permit at six months intervals during the first two years of operation of the State program shall at a minimum include the following:

(1) The data required in § 146.24(a)(1);

(2) The data required in § 146.24(a)(3) including, under location, the distance and direction from the injection well;

(3) The depth to the top and bottom of any USDW;

(4) The distance to the nearest down-gradient water supply well;

(5) A description of the geology and hydrology of the area;

(6) The construction characteristics of the well;

(7) The corrective action proposed as well as that performed; and

(8) Any reporting to the Director under § 122.41(d).

(b) The Director shall also submit the type and results of all Mechanical Integrity tests reported on existing wells and new (conversion only) wells during the first two years of operation.

(c) The Director shall require a temperature log or noise log, on a sample of Class II wells in cases where operators submitted cementing records to meet the requirement of § 146.08(c). The wells to be tested shall be chosen by a formal random selection procedure. The sampling shall be done on a field or pool basis and be statistically representative of the wells in that field or pool. At a minimum, the sample size for each State shall be 100 wells or 5 percent of the number of Class II injection wells in the State whichever is smaller. At least half of the wells tested must be existing wells.

Subpart D—Criteria and Standards Applicable to Class III Wells

§ 146.31 Applicability.

This subpart establishes criteria and standards for underground injection control programs to regulate Class III wells.

§ 146.32 Construction requirements.

(a) All new Class III wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, axial loading, etc.;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluids and formation fluids;

(6) Lithology of injection and confining zones; and

(7) Type and grade of cement.

(b) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class III wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a qualified log analyst and submitted to the Director. The logs and tests appropriate to each type of Class III well shall be determined based on the intended function, depth, construction and other characteristics of the well, availability of similar data in the area of the drilling site and the need for additional information that may arise from time to time as the construction of the well progresses. At a minimum, such logs and tests shall include deviation checks conducted on all holes where pilot holes and reaming are used, at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling.

(c) Where the injection zone is a water bearing formation, the following information concerning the injection zone shall be determined or calculated for new Class III wells:

(1) Fluid pressure;

(2) Temperature;

(3) Fracture pressure;

(4) Other physical and chemical characteristics of the injection zone;

(5) Physical and chemical characteristics of the formation fluids; and

(6) Compatibility of injected fluids with formation fluids.

(d) Where the injection formation is not a water bearing formation, the information in paragraph (c)(3) of this section must be submitted.

(e) Where injection is into a formation which contains water with less than 10,000 mg/l TDS monitoring wells shall be completed into the injection zone and into any underground sources of drinking water above the injection zone which could be affected by the mining

operation. These wells shall be located in such a fashion as to detect any excursion of injection fluids, process by-products, or formation fluids outside the mining area or zone. If the operation may be affected by subsidence or catastrophic collapse the monitoring wells shall be located so that they will not be physically affected.

(f) Where injection is into a formation which does not contain water with less than 10,000 mg/l TDS, no monitoring wells are necessary in the injection stratum.

(g) Where the injection wells penetrate an USDW in an area subject to subsidence or catastrophic collapse an adequate number of monitoring wells shall be completed into the USDW to detect any movement of injected fluids, process by-products or formation fluids into the USDW. The monitoring wells shall be located outside the physical influence of the subsidence or catastrophic collapse.

(h) In determining the number, location, construction and frequency of monitoring of the monitoring wells the following criteria shall be considered:

(1) The population relying on the USDW affected or potentially affected by the injection operation;

(2) The proximity of the injection operation to points of withdrawal of drinking water;

(3) The local geology and hydrology;

(4) The operating pressures and whether a negative pressure gradient is being maintained;

(5) The toxicity and volume of the injected fluid, the formation water, and the process by-products; and

(6) The injection well density.

§ 146.33 Operating, monitoring, and reporting requirements.

(a) *Operating Requirements.* Operating requirements prescribed shall, at a minimum, specify that:

(1) Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone, initiate fractures in the confining zone or cause the migration of injection or formation fluids into an underground source of drinking water; and

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.

(b) *Monitoring Requirements.* Monitoring requirements shall, at a minimum, specify:

(1) The analyses of the physical and chemical characteristics of the injected fluid with sufficient frequency to yield representative data on its characteristics;

(2) Installation and use of continuous recording devices to monitor the injection pressure, flow rate and volume;

(3) Demonstration of mechanical integrity pursuant to § 146.08 at least once every five years during the life of the well for salt solution mining and geothermal wells only;

(4) Weekly monitoring of fluid level and the parameters chosen to measure water quality in the injection zone; and

(5) Quarterly monitoring of wells adjacent to the injection site to detect any migration from the injection zone into an USDW.

(6) All Class III wells may be monitored on a field or project basis rather than an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.

(c) *Reporting Requirements.* Reporting requirements shall, at a minimum, include:

(1) Quarterly reporting to the Director on required monitoring;

(2) Results of mechanical integrity and any other periodic test required by the Director reported with the first regular quarterly report after the completion of the test; and

(3) Monitoring may be reported on a project or field basis rather than individual well basis where manifold monitoring is used.

§ 146.34 Information to be considered by the Director.

This section sets forth the information which must be considered by the Director in authorizing Class III wells. Certain maps, cross sections, tabulations of wells within the area of review, and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class III well or area to operate or the construction of a new Class III well the Director shall consider the following:

(1) Information required in 40 CFR 122.4 and 122.38(c);

(2) A map showing the injection well(s) for which the permit is sought and the applicable area of review. Within the area of review, the map must show the number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, mines (surface and subsurface), quarries, public water systems, water wells and other pertinent surface features including residences and roads. The map should also show faults if known or suspected. Only information of public record is required to be included on this map;

(3) A tabulation of data on all wells within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the Director may require;

(4) Maps and cross sections indicating the vertical and lateral limits of all underground sources of drinking water within the area of review, their position relative to the injection formation, and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection;

(5) Maps and cross sections detailing the geologic structure of the local area;

(6) Generalized map and cross sections illustrating the regional geologic setting;

(7) Proposed operating data:

(i) Average and maximum daily rate and volume of fluid to be injected;

(ii) Average and maximum injection pressure; and

(iii) Source and an analysis of the chemical, physical, biological and radiological characteristics of the injection fluid.

(8) Proposed formation testing program to obtain an analysis of the physical, chemical and radiological characteristics of the receiving formation;

(9) Proposed stimulation program;

(10) Proposed injection procedure;

(11) Engineering drawings of the surface and subsurface construction details of the system;

(12) Plans (including maps) for meeting the monitoring requirements of § 146.33(b);

(13) Expected changes in pressure, native fluid displacement, direction of movement of injection fluid;

(14) Contingency plans to cope with all shut-ins or well failures so as to prevent the migration of contaminating fluids into underground sources of drinking water;

(15) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well as required by 40 CFR 122.42(9); and

(16) The corrective action proposed to be taken under 40 CFR 122.44.

(b) Prior to granting approval for the operation of a Class III well the Director shall consider the following information:

(1) All available logging and testing data on the well;

(2) A satisfactory demonstration of mechanical integrity for all new wells and for all existing salt solution and geothermal wells pursuant to § 146.08.

(3) The actual operating data;

(4) The results of the formation testing program;

(5) The actual injection procedures; and

(6) The status of corrective action on defective wells in the area of review.

(c) Prior to granting approval for the plugging and abandonment of a Class III well the Director shall consider the following information:

(1) The type and number of plugs to be used;

(2) The placement of each plug including the elevation of the top and bottom;

(3) The type, grade and quantity of cement to be used;

(4) The method of placement of the plugs, and

(5) The procedure to be used to meet the requirements of § 146.10(c).

§ 146.35 Mid-course evaluation requirements.

In compliance with 40 CFR 122.18(c)(4)(C)(ii) the data to be submitted on each Class III permit at six month intervals during the first two years of operation of the State program shall at a minimum include the following:

(a) The data required in § 146.14(a)(i);

(b) The data required in § 146.34(a)(3) including, under location, the distance and direction from the injection well;

(c) The depth to the top and bottom of any USDW;

(d) The distance to the nearest down-gradient water supply well;

(e) A description of the geology and hydrology of the area;

(f) The construction characteristics of the well;

(g) The type and results of all mechanical integrity tests reported to the Director during the first two years of the program; and

(h) Any reporting to the Director under § 122.41(d).

Subpart E—Criteria and Standards Applicable to Class IV Injection Wells [Reserved]

Subpart F—Criteria and Standards Applicable to Class V Injection Wells

§ 146.51 Applicability.

This subpart sets forth Criteria and Standards for underground injection control programs to regulate all injection not regulated in Subparts B, C, D, and E.

(a) Generally, wells covered by this Subpart inject non-hazardous fluids into or above formations that contain underground sources of drinking water. It includes all wells listed in § 146.05(e) but is not limited to those types of injection wells.

(b) It also includes wells not covered in Class IV that inject radioactive materials listed in 10 CFR Part 20, Appendix B, Table II, Column 2, and injection wells used to store hydrocarbons which are gases at standard temperature and pressure.

§ 146.52 Inventory and Assessment.

(a) The owner or operator of any Class V well shall, within one year of the effective date of an underground injection control program, notify the Director of the existence of any well meeting the definitions of Class V under his control, and submit the inventory information required in 40 CFR 122.37(c)(1).

(b) Within three (3) years of approval of the State program the Director shall complete and submit to EPA a report containing:

(1) The information on the construction features of Class V wells, and the nature and volume of the injected fluids;

(2) An assessment of the contamination potential of the Class V wells using hydrogeological data available to the State;

(3) An assessment of the available corrective alternatives where appropriate and their environmental and economic consequences; and

(4) Recommendations both for the most appropriate regulatory approaches and for remedial actions where appropriate.

PART 122—MARINE SANITATION DEVICE STANDARD

2. 40 CFR is amended by revising Part 122 as follows:

§ 122.18 [Amended]

a. Section 122.18 is amended by deleting paragraph (c)(4)(ii) and substituting in lieu thereof the following:

* * * * *

(c) * * *

(4) * * *

(ii) In addition to complying with the requirements of paragraph (c)(4)(i) of this section, the Director shall provide the Administrator, on February 28th and August 31st of each of the first two years of program operation, the information required in 40 CFR 146.15, 146.25, and 146.35.

§ 122.37 [Amended]

b. Section 122.37 is amended by deleting paragraph (a) and substituting in lieu therefore the following:

(a) *Types of underground injection which may be authorized by rule.* The Director may authorize underground injection by rule as outlined in this paragraph.

(1) Injection into exisiting Class I, II (except existing enhanced recovery and hydrocarbon storage), and III wells may be authorized by rule for periods up to five years from the date of approval or promulgation of the UIC program. All such wells must be issued permits within the five year period.

(i) Rules under paragraph (a)(1) of this section shall specify that the authorization to inject shall exprire:

(A) Upon the effective date of the permit or permit denial, if a permit application has been filed in a timely manner as specified in § 122.38(b)(1);

(B) If a permit application has not been filed in a timely manner as specified in § 122.38(b)(1); or

(C) Unless a complete permit application is pending, not later than five years after the approval or promulgation of the UIC program.

(ii) Notwithstanding the prohibition in § 122.33, rules under paragraph (a)(1) of this section authorizing Class II and Class III operations or projects in existing injection fields may allow them to continue normal operations until permitted, including construction and operation of new injection wells as part of the operation, provided the owner or operator maintains compliance with all applicable requirements.

(iii) Rules under paragraph (a)(1) of this section shall apply, and ensure compliance no later than one year after authorization by such rules, with the following requirements applicable to permittees, except the terms "permit" and "permittee" shall be read to include rules and those authorized by rule:

(A) Section 122.41(a)—(exemption from rule where authorized by temporary permits);

(B) Section 122.41(b)—(retention of records);

(C) Section 122.41(d)—(reporting within 24 hours);

(D) Section 122.41(e)—(180 days notice of abandonment);

(E) Sections 122.42(f) and 146.10—(plugging and abandonment);

(F) Operating, monitoring, and reporting requirements (except mechanical integrity) under § 146.13 (Class I), § 146.23 (Class II) and § 146.33 (Class III);

(G) Section 122.42(g)—(financial responsibility); and

(H) Section 122.45(c)—(requirements for wells injecting hazardous waste) applicable to class I wells injecting hazardous waste only.

(2) Injection into existing Class II enhanced recovery and hydrocarbon storage wells may be authorized by rule for the life of the well or project.

(i) Such rules promulgated by the Director shall apply the following requirements applicable to Class II permittees, except that the terms "permit" and "permittee" shall be read to include rules and those authorized by rule:

(A) Section 122.41(a)—(exemption from rule where authorized by temporary permit);

(B) Section 122.41(b)—(retention of records);

(C) Section 122.41(d)—(reporting within 24 hours);

(D) Section 122.41(e)—(180 days notice of abandonment);

(E) Sections 122.42(f) and 146.10—(plugging and abandonment);

(F) Section 122.42(g)—(financial responsibility);

(G) Section 146.08—(mechanical integrity);

(H) Section 146.22—(construction requirements); and

(I) Section 146.23—(operating, monitoring and reporting requirements).

(ii) Such rules shall establish compliance schedules for achieving the construction requirements no later than three years and other requirements no later than one year after authorization.

(3) Injection into existing Class IV wells injecting directly into USDWs may be authorized for a period not to exceed six months after approval or promulgation of the UIC program. Such rules shall apply the requirements of § 122.45(c).

(4) Injection into Class V wells may be authorized by rule until requirements under future regulations become applicable.

c. Section 122.37 is further amended by deleting paragraph (b) and re-lettering paragraphs (c), (d) and (e) as paragraphs (b), (c) and (d).

d. Section 122.27 is further amended by deleting new paragraph (c)(1) and substituting in lieu thereof the following:

* * * * *

(c) * * *

(1) *Contents.* As part of the inventory, the Director shall require at least the following information:

(i) Facility name and location;

(ii) Name and address of legal contact;

(iii) Ownership of facility;

(iv) Nature and type of injection wells; and

(v) Operating status of injection wells.

(Note.—This information is requested on national form "Inventory of Injection Wells," OMB No. 158–R0170).

§ 122.41 [Amended]

e. Section 122.41 is amended by adding a new sentence at the end of paragraph (e) as follows:

* * * * *

(e) * * * With the notice, the permittee shall submit a revised plugging and abandonment plan updated as appropriate in compliance with § 122.42(f) and § 146.10.

§ 122.17 [Amended]

f. Section 122.17(f) is amended by adding a new paragraph (3) as follows:

(f) * * *

(3) Amend a plugging and abandonment plan which has been updated under § 122.41(e).

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